IVANHOE ENERGY

2000

Advancing The Green Fuels Megatrend

MISSION & PROFILE

Advancing The Green Fuels Megatrend

As people of the world's cities demand healthier air, an undeniable trend to cleaner transportation fuels is taking shape. Gas-to-liquids (GTL) technology, which enables the commercial production of everyday oil products synthetically, is empowering the petroleum industry to use clean natural gas instead of conventional black oil as the source of feedstock. The result is a new generation of green transportation fuels for motor vehicles, aircraft and ships. Ivanhoe Energy is Advancing the Green Fuels Megatrend.

Mission

Ivanhoe Energy's mission is to create wealth for its shareholders, initially focusing on:

1. Production of cleaner burning fuels from natural gas, using proven GTL technology.
2. Conventional exploration and production (E&P), primarily natural gas in the U.S.
3. Enhanced oil recovery (EOR) and natural-gas projects, on a production-sharing basis with national petroleum companies.

Profile

Ivanhoe Energy is led by a business team with a unique combination of global success in finding oil and gas reserves and in arranging capital for resource development. Ivanhoe's portfolio contains exceptional opportunities.

Ivanhoe is demonstrating environmental leadership through its investments in gas-to-liquids projects designed to produce ultra-clean transportation fuels from stranded natural-gas deposits around the world. Ivanhoe holds a master license for the Syntroleum GTL technology.

Ivanhoe's major E&P properties are located in the United States and in China. The California portfolio includes about 30 prospects and drilling leads in the San Joaquin Basin. In Texas, the company has large development programs in the Bossier gas play and in the Spraberry oil trend.

Ivanhoe has EOR projects and is pursuing natural-gas developments in several onshore petroleum basins in China.

Ivanhoe's stock trades on the Nasdaq National Market under the symbol IVAN, and on The Toronto Stock Exchange under the symbol IE.

LETTER TO SHAREHOLDERS

Building a Premier Energy Company

The Ivanhoe Energy story lit a flame with investors during the energy boom of 2000. Thanks to investors' confidence, Ivanhoe turned in a sector-leading performance during the year, achieving a 175% increase in trading value and outperforming all of the other companies in the TSE 300 Oil and Gas Index. Our shares now trade on Nasdaq, providing greater liquidity to our investors, and we have appointed Salomon Smith Barney as our financial adviser.

When we joined Ivanhoe in 1998, our goal was to build another premier energy company, emulating our earlier success in helping to establish Occidental Oil & Gas as a global market player.

Our strategy is quite clear. We plan to build a large, successful energy company, using our career experience and the many relationships that we have built over the years. Our people are among the best and we have access to state-of-the-art technology. We believe that the investments we are making in conventional E&P projects will fund our higher-potential exploration programs. We plan to have exploration discoveries generate the cash needed to fund the greatest upside of all – the construction of world-class, GTL conversion plants on top of existing fields of stranded gas.

World oil prices rallied greatly during 2000 and North American natural-gas prices rose to levels unseen since the deregulation of U.S. markets. Despite the greater resolve of OPEC to maintain prices in the mid-$20 range and the perceived inability of the industry to fulfill the growing demand for gas, we continue to expect price volatility and cycles. Our planning forecast calls for benchmark pricing of West Texas Intermediate crude and Henry Hub gas at well below current trading levels.

Ivanhoe has made significant advances, assembling a substantial base of assets and opportunities. In California, we have one of the largest, most prospective positions in the San Joaquin Basin, and one of the industry's most comprehensive seismic databases. With our partner, Aera Energy – California's largest oil and gas producer – we have started drilling our inventory of 30 prospects and leads. A major event in 2001 will be the drilling of our first deep-gas target in the Temblor formation, close to the East Lost Hills discovery. Ivanhoe has a large exploration block on trend with, and adjacent to, this discovery, which analysts believe could hold trillions of cubic feet of gas and represent one of the largest gas discoveries in decades in the lower-48 states.

We are very pleased with our rapidly expanding Spraberry and Bossier plays in Texas, and our oil recovery and gas projects in China. Each has the potential to create strong growth in volumes, earnings and cash flow.

Ivanhoe has acquired a master license from Syntroleum and agreed to be a partner in Australia's Sweetwater project, the first commercial application of the industry-leading GTL process. We are also working with several national petroleum companies on proposals to build GTL projects as large as 160,000 barrels a day.

Engineering advances have dramatically reduced the capital costs of producing green fuels from natural gas. The major consuming nations of the world are looking for energy solutions that reduce health hazards and greenhouse gases without jeopardizing the benefits of economic growth. The people of Ivanhoe have the experience to understand the challenges, the vision to see the potential and the determination to put this company in the vanguard of the green fuels megatrend.

David Martin
Chairman

Leon Daniel

Leon Daniel
President & CEO
March 16, 2001

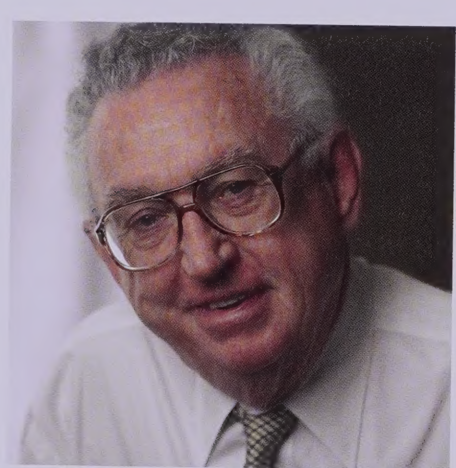
LEADERSHIP

The Wealth Of 170 Years Of Oil And Money Acumen

Ivanhoe Energy benefits from its leadership team's unique blend of expertise in the petroleum industry and in financial markets. Individually, team members are proven deal makers, oil finders, pipeline builders, oil-field managers and accomplished financiers. As leaders of Ivanhoe Energy, their reputations are their entrées to the executive suites and the banking halls of the world.

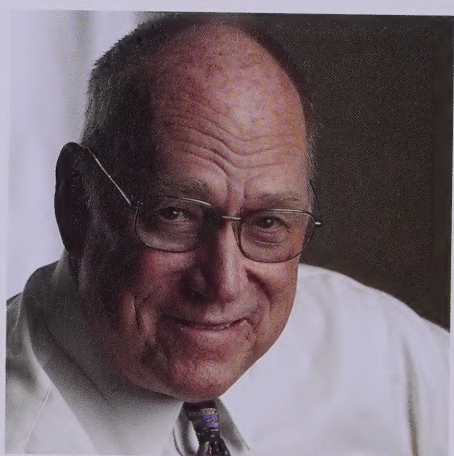
From the sands of Qatar to the depths of the North Sea, the passes of the Andes and the jungles of Sumatra, Ivanhoe's leaders have earned their stripes as resource developers and oilmen of distinction. In the process, some of them helped to build Occidental Petroleum from a bold ambition into one of the world's most successful producers.

Ivanhoe's leaders know what it takes to be successful. Now they are using more than 170 years of combined career knowledge and contacts to build Ivanhoe Energy into a focused, international company that is being recognized in the world's energy capitals and money centres.



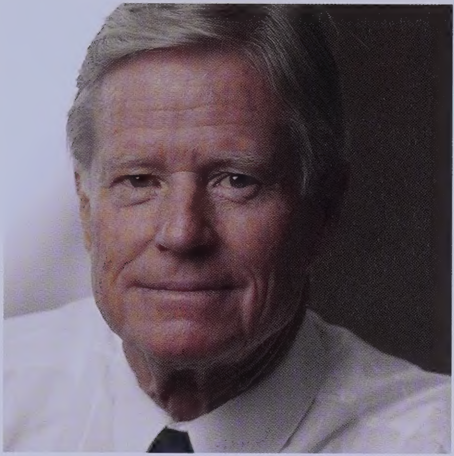
David Martin, Chairman

Part of the founding team at Occidental Petroleum, Mr. Martin was President & CEO of Occidental Oil & Gas Corporation, of California, from 1986 to 1996. He also was former Executive Vice-President and a director of Occidental Petroleum Corporation, and a Director of Canadian Occidental Petroleum. A geologist, he has 39 years of international experience in the oil and gas industry, 26 of them in senior management positions with Occidental Petroleum Corporation.



Leon Daniel, President & Chief Executive Officer

A petroleum engineer and specialist in enhanced oil-recovery techniques, Mr. Daniel was formerly Executive Vice-President of Worldwide Business Development for Occidental Oil and Gas Corp., of California, from 1996 to 1998, and President, Occidental Engineering Co., between 1993 and 1996. His 40 years of experience in the oil and gas industry include successful oil-field projects in Qatar, Venezuela, Libya, the North Sea, Colombia, Russia and the U.S.

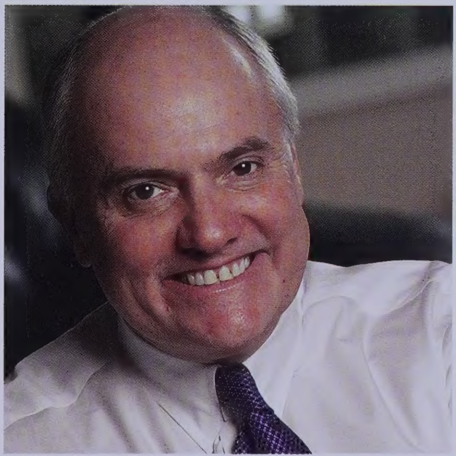


John Carver, DIRECTOR

Mr. Carver, a petroleum geologist, was Executive Vice-President of Worldwide Exploration for Occidental Oil & Gas Corporation between 1994 and 1997. His 40 years of experience in the oil and gas industry include 25 years as a senior executive involved in international exploration for Occidental Petroleum.

Robert M. Friedland, DEPUTY CHAIRMAN

An international financier, and Chairman and President of Ivanhoe Capital Corporation, Mr. Friedland has been associated with resource and technology ventures for 20 years. He was named Developer of the Year in 1996 by the Prospectors and Developers Association of Canada for his work in establishing and financing international mining and exploration companies, including Diamond Fields Resources, whose Voisey's Bay nickel deposit was sold to INCO Limited for CDN$4.3 billion.



John O'Keefe, CHIEF FINANCIAL OFFICER

Mr. O'Keefe has 27 years' experience in the energy industry, which has included responsibilities for financial planning and analysis, investor relations, corporate finance, treasury, accounting and auditing. He is also Ivanhoe's Executive Vice-President of Investor Relations, and was formerly Vice-President, Investor Relations, with Santa Fe Snyder Corp. and Oryx Energy Company, both of Texas.

IVANHOE ENERGY

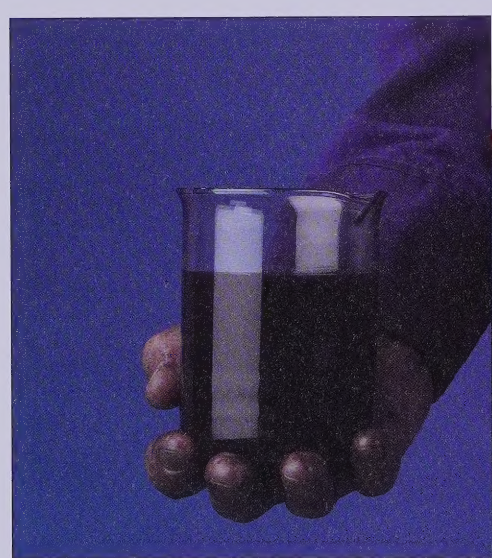
AREAS OF OPERATIONS


CAIRO
POTENTIAL GTL PROJECTS
DOHA
DAQING
BEIJING
DAGANG
TOKYO
SICHUAN
SWEETWATER GTL
PERTH

Ivanhoe Holds Master License For Gas-To-Liquids Technology – A Key To Clean Air And Healthier Cities

GAS-TO-LIQUIDS

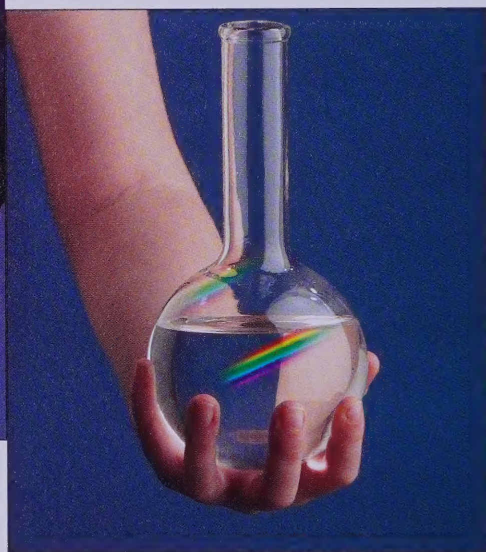
Ivanhoe Energy has joined a select group of industry-leading companies that are showing the way to the commercialization of a new generation of green fuel products. These products are derived from large deposits of low-cost natural gas currently locked in remote energy basins around the world, with no economic transportation link to markets.



Today's familiar black oil...

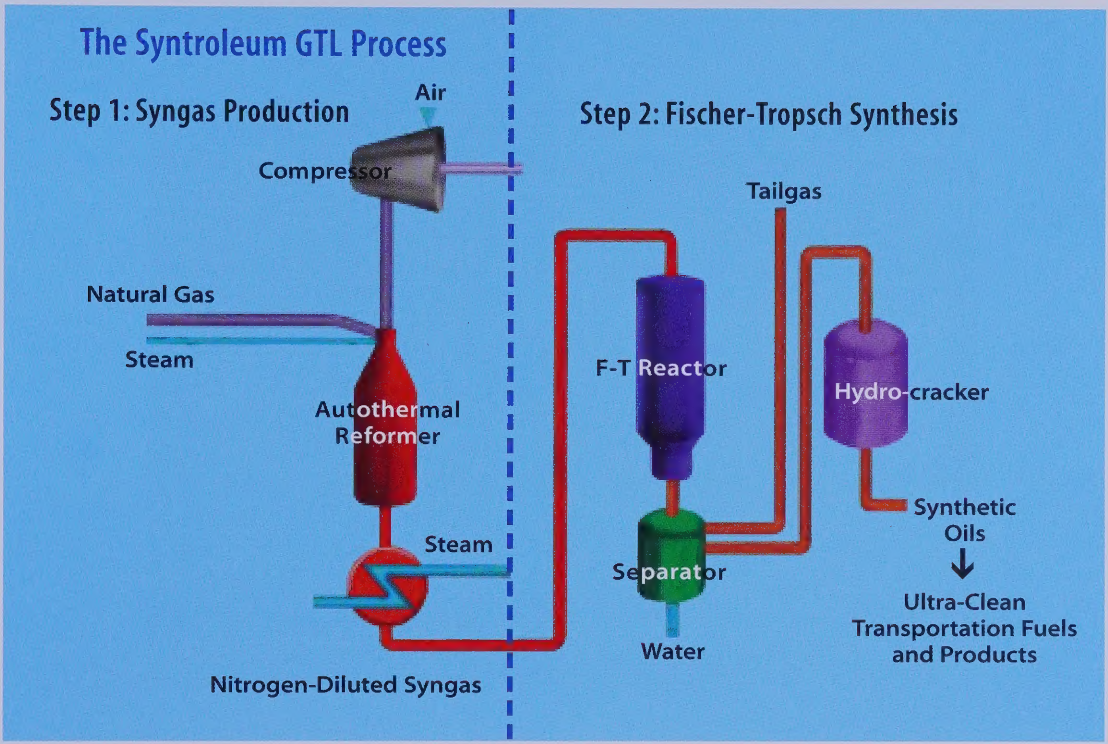
Ivanhoe has acquired a master license from Syntroleum Corporation, securing rights to use its process to convert natural gas into transportation fuels on an unlimited number of projects around the world. Industry majors BP, Marathon and Texaco also hold Syntroleum licenses. Other major global energy companies are pursuing GTL projects, using variations on the basic chemistry pioneered in the 1920s by German scientists Franz Fischer and Hans Tropsch.

GTL fuels, such as ultra-clean diesel, contain non-detectable levels of sulfur, metals and aromatics. Diesel engines perform more efficiently on synthetic fuels because of the extra power from a higher cetane index and the elimination of contaminants that attack emission-reducing equipment. As a product, GTL fuels surpass new federal rules in the United States, Europe and Japan that require refineries to reduce the sulfur content of present-day diesel fuel by 97%, to 15 parts per million, over the next several years. Such regulations are providing the impetus to the introduction of new, green, designer fuels to a much wider market.



... tomorrow's sulfur-free green diesel

Since GTL diesel already exceeds the new worldwide specifications for low-sulfur diesel fuel, it will be in demand for blending with conventional diesel to satisfy increasingly stringent clean-air standards.



In the patented Syntroleum GTL process, natural gas is mixed with compressed air and steam to produce a synthesis gas. Then, through a catalytic reaction, the gas is converted to a range of ultra-clean synthetic oils, which can be further refined to produce transportation fuels and hydrocarbon products. Potentially valuable by-products include heat, which can be used to produce electricity, and agricultural-grade water.

The Syntroleum process is a cost-effective refinement of GTL technology that has been in use for generations. A major advantage is that the process uses compressed air instead of pure oxygen to facilitate the conversion reaction, substantially reducing the capital cost and vastly improving safety at the process plants.

The auto industry has rapidly developed new engine technologies that, with GTL fuels, can meet clean-air standards – giving green fuels a clear economic advantage. The first cars powered by fuel cells should be available to consumers within five years. GTL fuel, with its high hydrogen content, is ideal for use with fuel cells. Stripping sulfur out of traditional crude-oil products is prohibitively expensive.

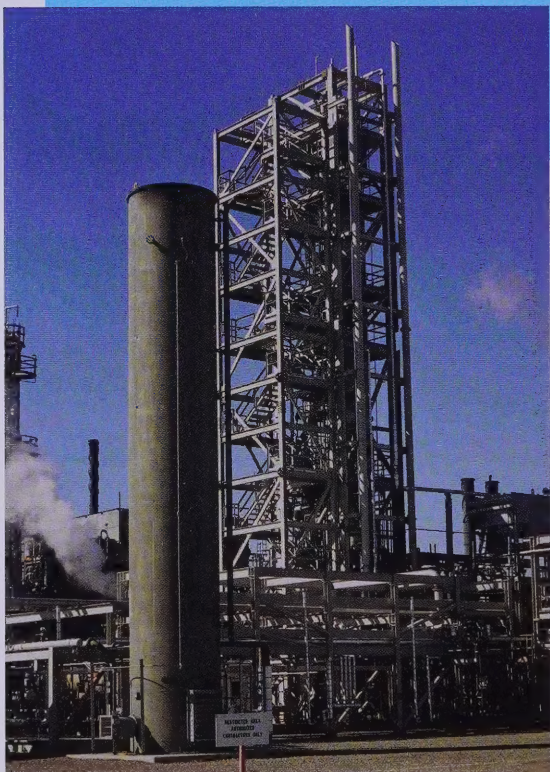
Fortunately, Ivanhoe is unfettered by investments in traditional crude-oil refineries. Recognizing that environmental necessities present business opportunities, Ivanhoe has invested in an international license to use the Syntroleum process, positioning itself as a producer of green fuels, with a strategic key to unlock the vast potential of stranded natural gas.

SWEETWATER GTL PLANT

Ivanhoe Energy Is A Partner In Synthetic-Oil Project In Australia

Ivanhoe Energy decided in October, 2000, to participate in Syntroleum's Sweetwater project, which is to be built on Western Australia's Burrup Peninsula. The project, based on a 10,000-barrel-a-day plant, will convert natural gas into ultra-clean, synthetic specialty products such as lubricants, industrial fluids and paraffins, as well as sulfur-free fuels. Ivanhoe paid $2 million toward the cost of front-end engineering and agreed to acquire a 13% equity position in the Sweetwater project for an additional $19 million, subject to project financing. Syntroleum expects to complete financing arrangements for Sweetwater by mid-2001. A 20-year gas supply has been secured from the North West Shelf.

Ivanhoe's commitment to the Sweetwater project gives the company a strategic advantage in implementing its plan to use Syntroleum's technology to monetize large, stranded gas deposits while producing easily transportable, clean fuels that can reduce greenhouse-gas emissions worldwide. Ivanhoe is working to secure agreements in several countries, including Qatar and Egypt, to obtain supplies of stranded natural gas as feedstock for major gas-to-liquids projects.



Syntroleum pilot plant successfully demonstrated the viability of producing synthetic oil from natural gas.

The Economics Of Green Oil

Synthetic oils can be produced and transported to markets at costs that are highly competitive with conventional crude oil at currently prevailing prices.

Approximately 11,000 cubic feet of natural gas are required to produce one barrel of synthetic oil, using a GTL process. Once in an unpressurized, liquid state, synthetic products can be stored and transported to market by road, rail or ocean tankers, just like conventional crude-oil products.

Although Ivanhoe is concentrating on agreements for larger-scale installations, the Syntroleum process has been designed to be profitable on plants producing less than 2,000 barrels a day. This gives the technology the potential to be applied on more than half of the currently known gas fields, containing more than 95% of the world's known gas.

A New Era Of Designer Fuels

Synthetic oils converted from natural gas are producing the cleanest fuels the world has ever seen. Global automaker DaimlerChrysler has tested Syntroleum's green diesel in its engines and confirmed its performance.

Syntroleum is working with the automotive industry to develop designer fuels from natural gas that will allow the manufacturers to produce engines and emission-control technologies to reduce emissions from transportation fuels.

Dodge Power Wagon runs on GTL green diesel

In addition to ultra-clean diesel for cars, trucks, buses and locomotives, Syntroleum synthetic oil also can produce:

- *Hydrogen-rich fuel for fuel cells that will power cars, buses and generators.*
- *Jet fuel.*
- *White oils for use in pharmaceuticals and cosmetics.*
- *Synthetic base oils for automotive and industrial greases.*
- *Non-toxic and biodegradable solvents.*
- *Home-heating fuels.*
- *Base oils, paraffins and naphtha used in making plastics.*
- *Drilling fluids.*

Principal Benefits Of GTL Technology

Attaching value to stranded natural gas

As much as 5,400 trillion cubic feet of natural gas lie in remote locations and have little economic value. GTL technology has the potential to convert the stranded gas into billions of barrels of economic value. Countries that control the gas would realize great value and also benefit from the investment and jobs that would result from development of the deposits.

Eliminating costly, polluting practices

GTL will help to eliminate oil-field flaring and the cost of reinjecting natural gas into the ground. This will permit early production from fields where oil otherwise would remain shut in by the inability to dispose of associated gas.

Development of environmentally-superior, designer liquid fuels

GTL will yield synthetic hydrocarbons of the highest quality that can be used directly as fuels with a wide variety of uses, or blended with lower quality fuels to bring them up to more stringent environmental and performance specifications.

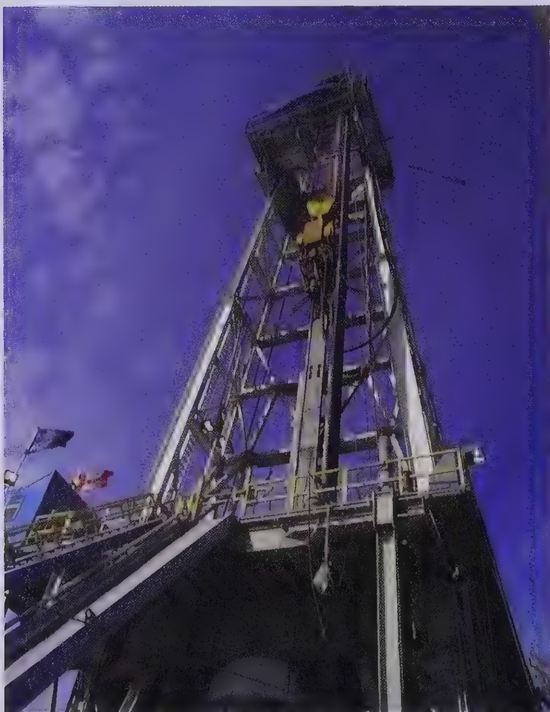
Compatibility with existing infrastructure

GTL fuels can be transported at no extra cost in conventional, clean tankers and also may be used in conventional pipelines, storage terminals and retail outlets.

IVANHOE JOINS QUEST FOR CALIFORNIA'S DEEP-GAS AT EAST LOST HILLS

UNITED STATES

The recovery of natural gas from up to four miles below the surface of the San Joaquin Basin, at East Lost Hills, in south-central California, is potentially one of the largest and most attractive energy plays in North America. In early 2001, natural gas was selling in California at more than double the Henry



California drilling: powerful Nabors rig contracted for the first Ivanhoe-Aera deep-gas well.

Hub benchmark price. Ivanhoe Energy has the position, the seismic data and the partner to play a major role in the action. Ivanhoe's primary joint-venture partner is Aera Energy, California's largest oil producer.

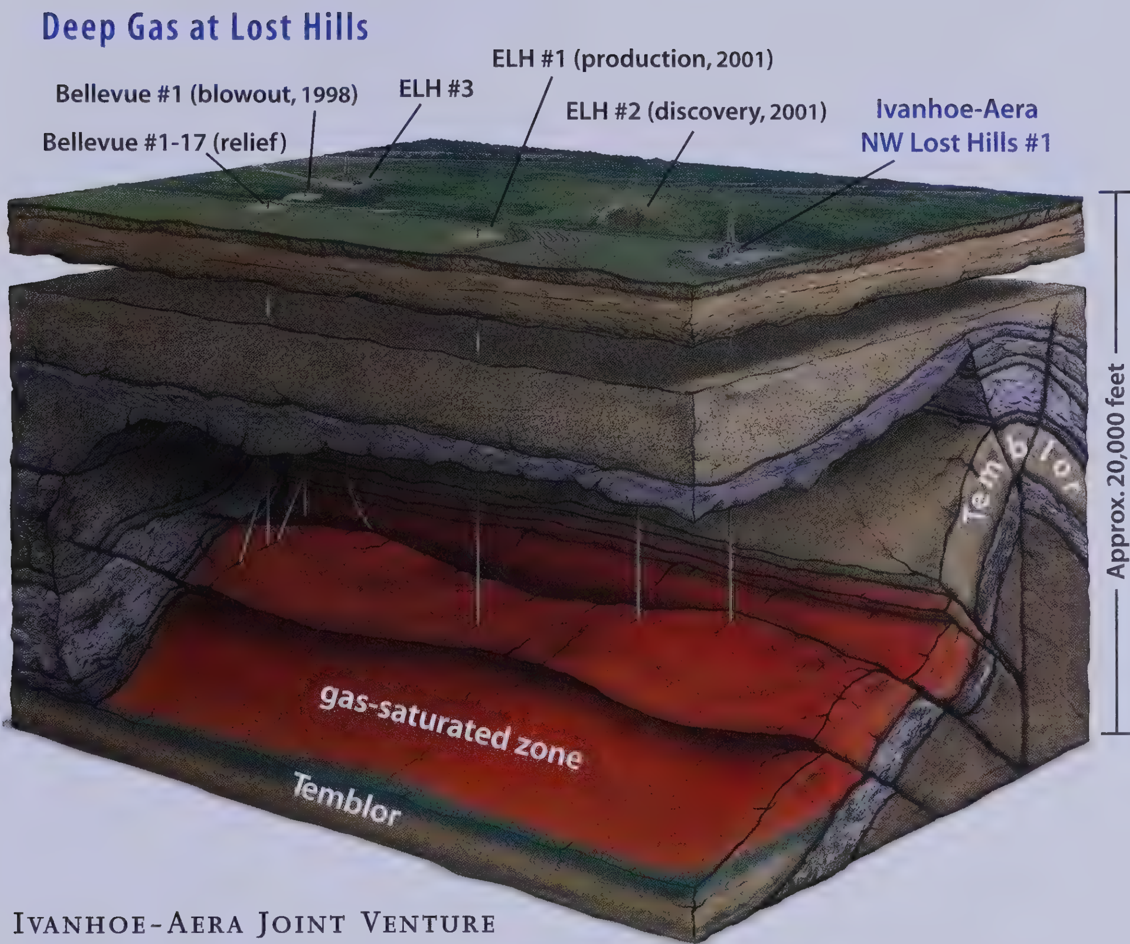
In February, 2001, gas from the East Lost Hills #1 well – the first Temblor deep well to be successfully completed – began flowing into the California distribution network at an initial rate of 15 million cubic feet a day (mmcf/d), with an increase planned to more than 20 mmcf/d. The well also produced 923 barrels of condensate a day. The ELH and nearby Bellevue wells were drilled by a consortium led by Berkley Petroleum, which was acquired by Anadarko Petroleum in March, 2001.

The ELH #1 well was further confirmation of a long-held belief that vast amounts of undiscovered gas were trapped in the Temblor formation along sub-thrust faults in the deepest part of the basin. Hydrocarbons locked in the shallower formations have sustained six of the largest 25 oil fields in the United States and yielded more than 13.5 billion barrels of oil equivalent over the past 100 years.

The significance of the East Lost Hills discovery was recognized by senior Ivanhoe executives, whose knowledge of the basin was instrumental in the 1998 decision to target Temblor deep gas and other prospects in California. Several months after Ivanhoe's decision, the gas first proved its existence when it incinerated a rig drilling the Bellevue #1 well at 17,600 feet.

Located several miles south of a prime exploration block held by Ivanhoe Energy and its partners, the Bellevue well, which had penetrated just 17 feet into the Temblor formation, flared an estimated 100 million cubic feet of gas and condensate a day for about a month. It continued flaring gas for more than three months until a relief well was drilled to shut off the blowout.

Industry and investor interest in the Lost Hills play intensified as natural gas prices soared in the energy crisis during the winter of 2000-2001. Steady progress was made in establishing the field's commercial viability. The East Lost Hills structure is estimated to be 12.5 miles long by 2.0 miles wide. Analysts believe that East Lost Hills contains a high-pressure, high-quality reservoir with enormous deliverability. Estimated to hold several trillion cubic feet of gas, it is one of the largest onshore gas discoveries in the lower-48 states.



Ivanhoe-Aera Joint Venture

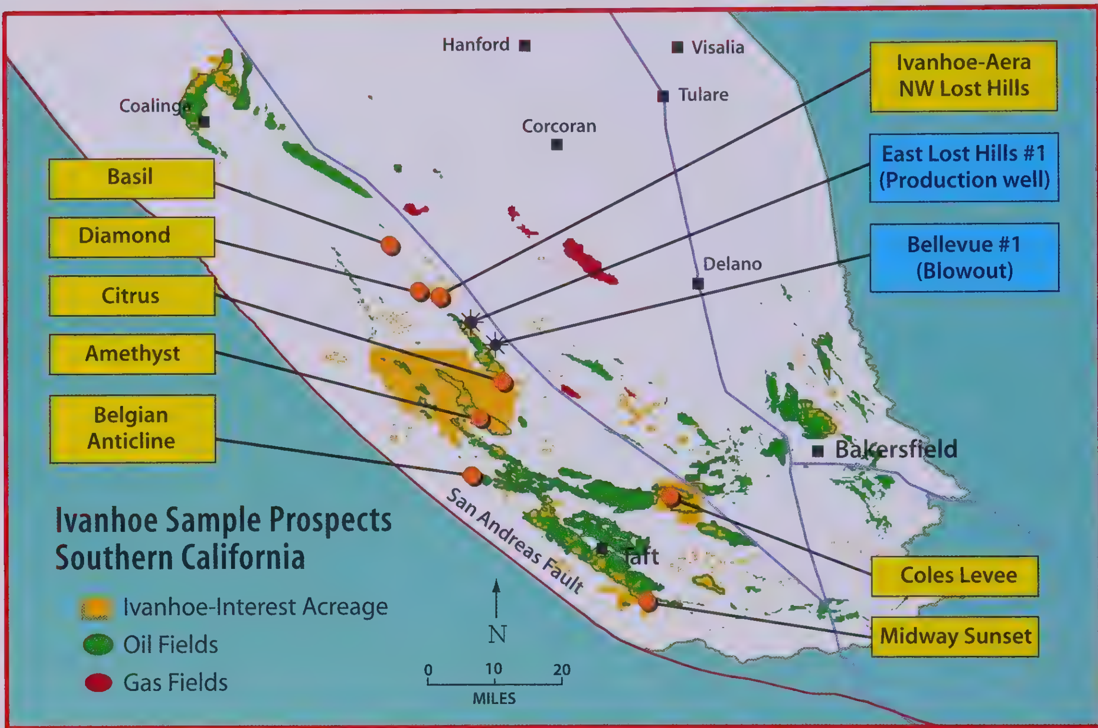
The Ivanhoe-Aera joint venture's first deep well in California, Northwest Lost Hills #1, is scheduled to spud in mid-2001. The well will target the gas-bearing Temblor sands intersected by the East Lost Hills #1 and #2 wells, at depths of up to 20,000 feet.

Ivanhoe and Aera have a 6,300-acre block overlying the northern end of the East Lost Hills structure, adjacent to acreage held by the ELH/Bellevue consortium. Ivanhoe has a working interest of 47% in the block, which dilutes to 42% if consortium members opt to join in the drilling of certain leases. Ivanhoe also holds gross overriding royalty interests of 1.4% on the entire block, plus an additional 1.8% to 6.6% on certain leases within the block.

The Ivanhoe-Aera joint venture at Northwest Lost Hills could tap a reservoir of several trillion cubic feet of gas. The well site is close to natural-gas gathering systems and water disposal facilities.

The structure's first appraisal well, ELH #1, two miles northwest of the Bellevue #1 blowout discovery well, was drilled to a depth of 19,700 feet to test the Phacoides interval in the lower Temblor sands. It intersected a total of 2,200 feet of Temblor sands. The operating consortium plans to have up to four deep-gas wells on-stream in 2001, northwest and southeast of the ELH #1 well.

California Interests Cover More Than 300,000 Acres



Ivanhoe Energy has been active in California's San Joaquin Basin since mid-1998, where it has assembled a large portfolio of interests in exploration prospects covering a total of more than 300,000 gross acres. In 2000, Ivanhoe Energy commenced production of oil from several shallow wells in the South Midway-Sunset area. The project is a low-risk, low-cost development in an area with extensive infrastructure and is providing immediate cash flow. Ivanhoe will be drilling numerous prospects in the San Joaquin Basin over the next few years, primarily below existing oil fields.

3-D Seismic Survey Treads Softly

Specialized, low-impact equipment (shown working in an almond orchard) was used to conduct a 3-D survey covering 80,000 acres on the western side of California's San Joaquin Basin. It is the largest such survey ever conducted in the basin.

Ivanhoe Energy and its survey partner, Prime Natural Resources, will use data from the comprehensive survey to identify multiple-depth targets, the first of which could be tested in 2001. Ivanhoe holds working interests ranging from 17.5% to 50% on key portions of the area.

Ivanhoe Holds Rights In Two Texas Oil And Gas Plays

UNITED STATES

Spraberry Oil and Gas

Ivanhoe Energy has acquired rights to participate in a 9,100-gross-acre development in the Spraberry trend of West Texas. Spraberry is part of the Permian Basin, one of the most productive regions in the United States, which contains several thousand producing oil and gas wells. It accounts for an estimated 15% of the combined annual oil output from the lower-48 states.

In early 2001, production from Ivanhoe's completed wells was averaging between 400 and 500 barrels of oil equivalent a day. The oil has a 40-degree API gravity, which sells at a premium of about $2.50 a barrel to the benchmark price for West Texas Intermediate crude.

Ivanhoe has a 62.5% interest in the project before payout and will have a 50% working interest after payout. The acreage could support approximately 100 new wells.

Bossier Gas

In late 2000, Ivanhoe Energy also entered the Bossier tight-gas-sand play in East Texas through its acquisition of prime exploration leasehold rights. Ivanhoe's 28,400 gross acres are adjacent to a gas discovery that is currently being developed, and on trend with many producing wells.

The Bossier sand play is a relatively new gas trend developed since 1996. Anadarko Petroleum has been a key force in developing the play. In Freestone County, the Bossier zone occurs at depths between 10,000 and 13,000 feet. Bossier sands are capable of stimulation by hydraulic fracturing. Combined gross gas production from the Bossier play is currently 280 million cubic feet (mmcf) per day. Operators have experienced average reserve sizes of about three billion cubic feet per well and initial production rates of approximately three mmcf/d. After the first year, Bossier wells have historically produced at a rate of about one mmcf per day.

Ivanhoe believes that there are additional Bossier opportunities in East Texas and is continuing to increase its acreage. The company will begin drilling a multi-well program in 2001 to evaluate up to 200 potential well locations over the next several years.

Anadarko estimates that a typical Bossier well has a breakeven at gas prices of $2 per mcf. Gas prices above this level make the economics of the Bossier wells exceptionally robust.

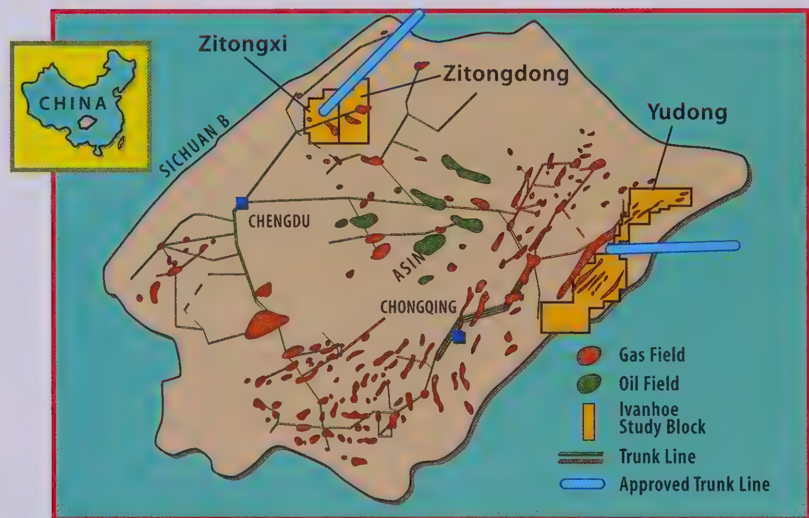
Ivanhoe currently holds a 73% working interest in the Bossier acreage, subject to leasehold burdens and a 9.375% net profits interest.

Sichuan Gas Deal Gives Ivanhoe Its Third Major Project In China's Booming Energy Sector

CHINA

Ivanhoe Energy's wholly-owned subsidiary, Sunwing Energy, signed new memoranda of understanding in February, 2001, that are expected to lead to a landmark, joint-venture development of oil and gas deposits in China's Sichuan Basin.

The basin is the most populous region in China, home to approximately 100 million people, and is also the country's largest gas-producing region. The exploration and development of cleaner burning natural gas has been made a national priority by the Chinese government. Most of the country's electricity is generated by the burning of coal, but the associated pollution, notably urban smog, is no longer acceptable in China.



Ivanhoe's MOUs with PetroChina were signed in Beijing as part of the Team Canada Trade Mission that was led by Prime Minister Jean Chrétien and received by Premier Zhu Rongji.

The MOUs give Ivanhoe the exclusive right to negotiate production-sharing contracts with PetroChina to develop and exploit the resources in three key blocks that contain highly productive natural-gas discoveries. The blocks, Zitongxi, Zitongdong and Yudong, cover more than 2.2 million acres, approximately 950 miles southwest of Beijing.

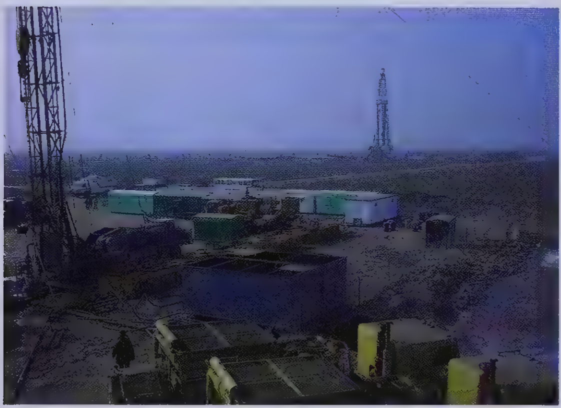
The blocks contain approximately 20 trillion cubic feet (tcf) of gas, according to estimates by Chinese engineers and geologists. The entire Sichuan basin contains an estimated 245 tcf of gas, and annual production is approximately 270 billion cubic feet.

Ivanhoe will conduct detailed feasibility studies, using internationally recognized, independent engineers, to establish the reserves on the three Sichuan blocks before finalizing production-sharing contracts. A total of 26 of the 39 wells previously drilled on the three blocks by PetroChina have been classified as producing gas wells. Most of the 38 known hydrocarbon-bearing structures on the three blocks have never been production tested.

Ivanhoe, through Sunwing, also is engaged in two enhanced oil recovery (EOR) projects in China.

Kongnan Project, Dagang

The Kongnan EOR project on the Dagang oil field is located in the southern part of the Huanghua Basin, approximately 60 miles south of Tianjin, in Hebei province. The area consists of 22,400 gross acres, contained in six blocks. PetroChina has drilled more than 80 wells on the blocks and has provided a substantial inventory of seismic data.



Two of the completed Ivanhoe wells now in production on the Dagang oil field.

The terms of the production-sharing contract allow Ivanhoe to pay 100% of the development costs to earn an 82% interest in the project prior to the recovery of the capital, and 49% thereafter. Nippon Oil Exploration funded 40% of the obligations in the Kongnan pilot project to earn a 20% participating interest.

Advanced technology, high-capacity pump has boosted production from an Ivanhoe well at Dagang.

Ivanhoe received encouraging results from the pilot program, which achieved production increases of up to 300% compared with original, offsetting wells drilled by local operators. The oil is being sold in U.S. dollars and the funds are being promptly remitted.

The Kongnan pilot program, completed in 2001, involved the workover of up to five existing wells and the drilling and testing of five new wells. It was designed to acquire technical data and to achieve higher production rates and recoveries by applying western drilling, completion and EOR techniques.

A long-term development plan provides for the drilling of 100 new wells and the reworking of 56 of 82 existing wells.

Zhaozhou Project, Daqing

This 8,100-gross-acre EOR project is located at the southern edge of the Daqing oil field, 60 miles southeast of Daqing, in the province of Heilongjiang.

PetroChina initially drilled and tested the field. Ivanhoe's pilot test involved the drilling of five wells and the establishment of a waterflood. Contract terms provide for Ivanhoe to earn an 85% interest in the project prior to the recovery of capital, and 49% thereafter.

Pilot well, Daqing

The overall development plan for the Daqing Zhou 13 Block has been approved. Pending further approvals, development drilling and facility construction at Daqing is expected to commence in the second half of 2001.

CORPORATE

Directors

David Martin	Chairman
Robert Friedland	Deputy Chairman
John Carver	
Leon Daniel	
Edward Flood	
Shun-ichi Shimizu	

Officers

Leon Daniel	President and Chief Executive Officer
John O'Keefe	Chief Financial Officer and Executive Vice-President
Pat Chua	Executive Vice-President
Gerry Moench	Executive Vice-President
Bradley Shoup	Executive Vice-President, Corporate Development
Beverly Downing	Corporate Secretary

Registrar And Transfer Agent

CIBC Mellon Trust Company
Vancouver, Canada
604 688 4330

Stock Listings

The Toronto Stock Exchange
Trading Symbol: IE

Nasdaq National Market
Trading Symbol: IVAN

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
For the fiscal year ended December 31, 2000.

or

☐ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
For the transition period from ____________ to ____________ .

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada
(State or other jurisdiction of incorporation or organization)

Not applicable
(I.R.S. Employer Identification No.)

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200 Burrard Street
Vancouver, British Columbia, Canada
V6C 3L6
(Address of principal executive offices)

(604) 688-8323
(Registrant's telephone number, including area code)

Securities to be registered pursuant to Section 12(b) of the Act: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, no par value	The Toronto Stock Exchange NASDAQ National Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

The aggregate market value of the voting stock held by non-affiliates of the Registrant on March 1, 2001 based on the closing price on the NASDAQ National Market on that date, was $373,264,526.

Documents incorporated by reference: None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to "dollars" or to "$" are to United States dollars and all references to "Cdn.$" are to Canadian dollars. The closing, low, high and noon buying rates in New York for cable transfers for the conversion of Canadian dollars into United States dollars for each of the four years ended December 31, 2000 as reported by the Federal Reserve Bank of New York were as follows:

	2000	1999	1998	1997
Closing	$0.6669	$0.6925	$0.6504	$0.6999
Low	0.6410	0.6441	0.6341	0.6945
High	0.6969	0.6925	0.7105	0.7487
Average Noon	0.6730	0.6730	0.6714	0.7198

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of United States dollars into Canadian dollars on March 1, 2001 was $0.6466 ($1.00 = Cdn.$1.5465). Exchange rates are based upon the noon buying rate in New York City for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York.

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report, the following terms have the following meanings:

Boe = barrel of oil equivalent
Bbl = barrel
MBbl = thousand barrels
MMBbl = million barrels
MBbl/d = thousand barrels per day
MMBl/d = million barrels per day
MMBtu = million British thermal units
Mcf = thousand cubic feet
MMcf = million cubic feet
Mcf/d = thousand cubic feet per day
MMcf/d = million cubic feet per day

When we refer to oil in "equivalents," we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized standard in which one Bbl is equal to six Mcf.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are "forward-looking statements". Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue and our negligible revenue since we lost control of our principal Russian project; losses and negative cash flow from our current exploration and development operations in California, Texas and China; our limited cash resources and consequent need for additional financing; uncertainties regarding the potential success of our oil and gas exploration and development projects in California, Texas and China; uncertainties regarding the potential success of gas-to-liquids technology; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe" or "continue" or the negative thereof or variations thereon or similar terminology.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an international energy company engaged in conventional oil and gas exploration and production, enhanced oil recovery projects and the development of gas-to-liquids projects. We were incorporated pursuant to the laws of the Yukon Territory, Canada, on February 21, 1995 under the name 888 China Holdings Limited. We were largely inactive until early 1996. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Our principal executive offices are located at 900 – 200 Burrard Street, Vancouver, British Columbia, V6C 3L6, and our registered and records offices are located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

OVERVIEW OF THE BUSINESS

Ivanhoe Energy Inc. is a company focused on three major strategies: (1) production of synthetic fuels from natural gas using gas-to-liquids ("GTL") technology; (2) conventional exploration and production ("E&P"), primarily natural gas in the United States; and (3) enhanced oil recovery ("EOR") and natural gas projects, on a production-sharing basis, with national petroleum companies.

Following our incorporation in February, 1995, we were largely inactive until early 1996, when we commenced our business as an acquirer, explorer and developer of oil and gas properties. Initially, we concentrated our efforts on acquiring oil and gas properties in Russia. Our strategy was to seek out existing oil and gas properties in Russia on which past drilling and field development practices did not maximize reserve recoveries and to establish joint ventures with local partners to rehabilitate existing wells to recover additional production.

In the third quarter of 1998, we began to implement a diversification program aimed at expanding the geographical scope of our business beyond Russia. We added three individuals to our Board of Directors who have international experience in the oil and gas industry. David Martin, who is now our Chairman, was formerly the President and Chief Executive Officer of Occidental Oil & Gas Corporation. E. Leon Daniel, who is now our President and Chief Executive Officer, and John Carver, who is now one of our directors, are also both former executives of Occidental Oil & Gas Corporation. In August, 1998, we began acquiring oil and gas exploration property interests in Peru and California. In 1999, we acquired property interests in China. In April, 2000 we acquired a limited volume license from Syntroleum Corporation ("Syntroleum"), to use its proprietary GTL technology to convert natural gas into synthetic fuels. We subsequently upgraded our limited volume license to a master license without volume limitations. Finally, in May, 2000, we began acquiring interests in oil and gas exploration properties in Texas.

In Peru, we earned a 50% participating interest in an exploration and development concession in the Ucayali Basin by funding drilling expenditures of approximately $13.5 million. The initial exploratory well was dry and we subsequently plugged and abandoned it. At this time we have no plans to continue exploration or development in Peru and we have relinquished our interest in the concession.

In Russia, a dispute with our joint venture partner prevented us from proceeding with our operations in the area. In the summer of 2000, we settled the dispute and sold our interest in our Russian properties. See Item 3. "Legal Proceedings".

In California, we have been accumulating working interests and royalty interests in the San Joaquin Valley since 1998. Our key asset in California is an exploration agreement with Aera Energy LLC ("Aera"), a company owned by two major integrated petroleum companies, which entitles us to explore and identify oil and gas prospects in the San Joaquin Valley using exploration, seismic and technical data owned by Aera. See "Oil and Gas Properties — California Properties".

In June, 1999, we further expanded the geographical scope of our business into China by acquiring Sunwing Energy Ltd. ("Sunwing"), an oil and gas company. As a result of our acquisition of Sunwing, we now have two production sharing contracts with China National Petroleum Corporation ("CNPC") which entitle us to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing, located in Heilongjiang Province. Nippon Oil Exploration Limited ("Nippon") of Japan is participating with us in the development of the Kongnan oilfield and holds a 20% working interest. See "Oil and Gas Properties — China Properties".

In February, 2001, we entered into two memoranda of understanding with PetroChina Corporation Limited, a subsidiary of CNPC. These memoranda give us the exclusive right to negotiate petroleum contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. The Sichuan Basin is a major oil and gas producing region of China located approximately 930 miles southwest of Beijing. We are undertaking feasibility studies on the three blocks. If the results are positive, we will commence negotiating production sharing contracts.

In May, 2000, we entered into an agreement with Discovery Operating, Inc. to earn a 62.5% working interest (reducing to 50% after cost recovery) in over 9,100 gross acres of oil and gas exploration property in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. We have also recently acquired a working interest in over 28,400 gross acres in the Bossier gas sands in East Texas. See "Oil and Gas Properties — Texas Properties".

We are also pursuing various opportunities to develop GTL projects using proprietary technology we licensed from Syntroleum. During 2000, we obtained a master license from Syntroleum to use its proprietary process to convert natural gas into synthetic oil, transportation fuels and other synthetic petroleum products. We plan to use the technology in areas with large natural gas deposits which would otherwise be uneconomic to develop. Our master license entitles us to use the Syntroleum proprietary process in an unlimited number of gas-to-liquids projects throughout the world (excluding North America, China and India).

We have also agreed in principle to become a partner in Syntroleum's Sweetwater GTL project in Western Australia. Subject to certain conditions, including Syntroleum's obligation to arrange project financing, we will invest $21 million to purchase a 13% equity interest in the project. See "Gas-to-Liquids Projects".

CORPORATE STRATEGY

Our goal is to create a diversified global energy company focused on GTL, E&P and EOR. We believe we can successfully implement our strategy and position ourselves to compete over the longer term in what we expect will be a rapidly evolving energy industry.

Our business plan is multi-faceted and involves the pursuit of objectives with short, medium and long term impacts on our business. Our short-term objective is to focus on areas where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established production in the Spraberry Trend of West Texas and at South Midway Sunset in the San Joaquin Basin of California. Sunwing has also established production at its Dagang project in China as part of its recently completed pilot-test program. Our Daqing project is also in production under the operatorship of CNPC. We will resume operatorship once we begin to implement our recently approved development plan. We continue to examine opportunities to expand our production.

The cornerstone of our medium term strategy is deep gas exploration in the San Joaquin Basin of California and in the Bossier gas sands of East Texas. Over the past two years, we have accumulated substantial acreage in the San Joaquin Basin. We recently completed an 80,000 acre three-dimensional seismic survey along the west side of the San Joaquin Valley which we are using to identify drilling targets. We plan to begin drilling our first deep gas exploration well in the Northeast Lost Hills area of the San Joaquin Basin with our partner, Aera, in the second quarter of 2001. In the fourth quarter of

2000, we purchased a working interest in over 28,400 gross acres of the Bossier sands of East Texas where we plan to drill gas targets in the third quarter of 2001.

We also continue to pursue our enhanced oil recovery initiatives in China. We are encouraged by the results achieved in our pilot programs at Dagang and Daqing and plan to proceed with the development phase of each project. The Chinese government approved our development plan for Daqing and we plan to submit our Dagang development plan to the government for approval in the third quarter of 2001. We also plan to seek other opportunities in China and elsewhere to acquire interests in fields with economic development potential.

Our long-term objective is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world's crude oil becomes more sour and heavy. We believe that Syntroleum's proprietary GTL technology holds significant potential for the economic production of synthetic fuels and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant construction is less expensive and the plant is safer to operate because, unlike competing technologies, it uses compressed air rather than oxygen.

With our master license to use Syntroleum's proprietary GTL technology, we are currently pursuing a number of opportunities in the Middle East and elsewhere to obtain rights to stranded natural gas deposits to use as feedstock for gas-to-liquids projects. We believe that synthetic fuels and specialty products produced using GTL processes will eventually present an attractive, economic and environmentally superior alternative to traditional fuels derived from crude oil.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

In April, 2000, we acquired a non-exclusive volume license entitling us to use Syntroleum's proprietary GTL process in an unlimited number of projects in all areas of the world (other than North America, China and India) subject to an aggregate limit of 50,000 barrels per day of synthetic GTL products. In October, 2000, we upgraded our volume license to a non-exclusive master license which entitles us to an unlimited number of GTL projects within the same geographical areas without any production volume limitations.

Syntroleum Process

Syntroleum's proprietary GTL process is designed to catalytically convert gas into synthetic liquid hydrocarbons. This process (the "Syntroleum Process") is designed to substantially reduce the capital and operating cost and the minimum economic size of a GTL plant.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process compresses air directly from the atmosphere when converting gas into synthetic hydrocarbons. The GTL processes developed by Syntroleum's competitors use either steam reforming or a partial combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for oxidation are bulky, expensive and increase operating costs. The Syntroleum Process allows for the operation of GTL plants without an air separation plant or steam reformer, thereby reducing capital costs, operating costs, the size and complexity of a GTL plant and operating volatility.

From our perspective, the greatest opportunity for the use of the Syntroleum Process lies in the extraction of stranded natural gas. Stranded gas exists in known reservoirs which cannot be marketed on

an economic basis. Operators consider gas to be stranded based on the relative size of the fields, the location of the gas relative to its market and the cost to transport the gas to markets.

Sweetwater GTL Project

In October, 2000, we signed a letter of intent to invest $21 million to participate as a 13% non-recourse equity partner in Syntroleum's Sweetwater GTL project under development in Western Australia. We made a $2 million advance which Syntroleum agreed to use for front-end engineering and other project development costs. Payment of the balance is subject to a number of conditions, including fulfilment of Syntroleum's obligation to arrange project financing.

The Sweetwater project is a nominal 10,000 barrels per day plant that will employ the Syntroleum Process to convert natural gas into ultra-clean synthetic specialty products such as lubricants, industrial fluids and liquid normal paraffins, as well as synthetic fuels. The plant will be located on the Burrup Peninsula in Western Australia and is scheduled for completion in 2003.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in the San Joaquin Valley area of California. We also hold interests in exploration and development properties in Texas, and China. An EOR development which we formerly operated in Russia was the subject of legal proceedings in the Russian courts and international arbitration proceedings in Stockholm. We settled these proceedings and sold our interest in our Russian projects. We held an interest in an exploration property in Peru but relinquished it during 2000. Set forth below is a description of our material oil and gas properties.

California Properties

Over the past three years, we acquired interests in a number of properties in the San Joaquin Basin area of California. To date, only our South Midway Sunset project contains known proved reserves and has wells on production. We cannot assure you that any of our other projects in California will result in the development of any producing wells or that production from such wells, if any, will be commercially viable.

Aera Agreement

In August, 1998, we entered into an agreement with Diatom Petroleum, Incorporated ("Diatom") whereby we acquired Diatom's rights to explore and earn working interests in exploration properties in the San Joaquin Valley held by Aera and others. Diatom's principal asset is an exploration agreement with Aera (the "Aera Agreement") which entitles Diatom to explore approximately 250,000 acres of Aera and other lands and identify prospects for drilling. In 1999, we acquired all of the outstanding shares of Diatom.

The lands in which we now hold exploration rights through Diatom are concentrated in areas adjacent to and under the North and South Belridge, Lost Hills, Midway Sunset, Coalinga, North and South Coles Levee, Yowlumne and Belgian Anticline fields. In carrying out our obligations under the Aera Agreement to identify drillable prospects, we are entitled to use all of the exploration, seismic and technical data owned by Aera.

Except for those preliminary prospects designated by us and accepted by Aera, our exclusive rights to explore Aera's properties will expire in September 2001 unless extended by mutual agreement. We will continue to hold exclusive exploration rights to the lands designated for a period of two years from the date that Aera accepts our prospect designation. During that time we are required to focus our activities on identifying drillable prospects within each preliminary prospect area. If, during this two year period, we identify a drillable prospect, Aera may elect to retain a working interest in the prospect. Although the Aera Agreement provides that Aera's working interest will range from a minimum of 25% to a maximum (depending on the location of the prospect) of 87.5%, we may negotiate different working interest

allocations with Aera on a prospect basis. Aera is obliged to assign to us any working interest in the prospect that it does not retain. Aera must also assign to Diatom, from all working interests, a 3.5% overriding royalty (the "Diatom Royalty"). The Diatom Royalty has been subdivided and allocated among various third parties. See Note 3 to our financial statements under Item 8 in this Annual Report. Once a drillable prospect is identified, we have two years to carry out exploration drilling. This two year period will be extended as long as we continue to drill or have established production.

The properties covered by the Aera Agreement are located in Kern, Kings, Tulare, Fresno, San Benito Monterey and San Luis Obispo Counties. Using the extensive proprietary seismic and technical databases owned by Aera and supplemented by us, we have identified over thirty leads within 14 preliminary prospect areas covering approximately 166,000 acres. To date, we have presented six drillable prospects to Aera for evaluation. Aera has elected to participate in four of the prospects presented for evaluation. These prospects are the Diamond prospect, the Northwest Lost Hills #1 prospect, the Amethyst prospect and the Belgian Anticline prospect. The Belgian Anticline prospect was drilled in December, 2000 and two other leads (Northwest Lost Hills #1 prospect and the Amethyst prospect) have been scheduled for drilling later in 2001. We have a 100% working interest in the two prospects in which Aera elected not to participate. One of these prospects is South Midway Sunset on which we have, to date, drilled 19 successful wells. The other prospect is Citrus, where we expect to drill our first well during the third quarter of 2001, depending on rig availability.

Set forth below is a description of our material exploration properties which are subject to the Aera Exploration Agreement.

- *East Lost Hills/Almond Flank Prospects*

In August, 1998, we took an assignment from Texaco Exploration and Production Inc. of its participating interest in the Almond Flank prospect, a northwestern extension of the Lost Hills field covering approximately 1,860 acres. We later acquired, for our own account, approximately 2,000 acres of additional leases in this area. We currently hold exploration rights to approximately 40% of the hydrocarbons in this area. The remaining interests are held by Aera and other parties. Total royalty burdens on the leases do not exceed 23.5%. The leases through which we hold our interests in the East Lost Hills and Almond Flank prospects expire between April, 2001 and January, 2005. We are currently negotiating an extension to the Texaco lease which is scheduled to expire on April 15, 2001.

We are developing two drillable prospects on our lease position in the northwestern Lost Hills area. Our first deep-gas exploration well in the San Joaquin Valley, known as the Ivanhoe Northwest Lost Hills #1, will be drilled in Kern County. Drilling is expected to commence in the second quarter of 2001. This prospect is a deep Temblor prospect which lies five miles northwest of, and on a trend with, the Bellevue No. 1 blowout well, drilled by Berkley Petroleum Corp. ("Berkley"), which was a Temblor gas discovery. In the 6,300 gross acres encompassing the Northwest Lost Hills prospect, we hold a maximum working interest of 47%. Berkley has the right to participate up to 33% in certain blocks within the acreage including Ivanhoe Northwest Lost Hills #1. If Berkley exercises this right, our average working interest in the acreage will be reduced to 42%.

In addition to our Northwest Lost Hills #1 prospect, we are evaluating the development potential of the Almond Flank prospect, which is a fractured Monterey play.

- *Amethyst Prospect (South Belridge)*

We have developed the Amethyst prospect in the northern part of the South Belridge area. We expect to commence drilling in the third quarter of 2001. We currently have a minimum working interest of 12.5% with Aera holding the balance.

- *Diamond Prospect*

We are developing the Diamond prospect in the Lost Hills area. We expect to complete a 3-D seismic survey over this prospect in the second quarter of 2001. We currently have a minimum working interest of 12.5% in this prospect, with Aera holding the balance.

- *Belgian Anticline Prospect*

We identified a drillable prospect on the western flank of the Belgian Anticline and spudded a well late in 2000. Three potential zones of hydrocarbon bearing sands totalling 240 gross feet were identified. In December, 2000, it was determined that two of the three zones were not capable of commercial production. Testing in the third zone is expected to be completed in the first half of 2001. We own a 40% working interest in the prospect with Aera holding the balance.

South Midway Sunset Project

We drilled 21 wells in the South Midway Sunset area in 2000. 19 of these wells are producing oil at commercial rates. We are currently producing approximately 250 barrels per day. We are considering production enhancement options, but have not yet attempted any such enhancements. The project is primarily designed to provide immediate cash flow from a low risk, low cost development project with existing infrastructure. We own a 100% working interest and a 92.9% revenue interest in the project. Aera elected not to participate in this project but receives royalties pursuant to the Aera Agreement.

Citrus Prospect

We have applied for a permit to drill a well in the Lost Hills area in 2001. This project is primarily designed to provide immediate cash flow from a low risk, low cost development project with existing infrastructure. We own a 100% working interest in the prospect.

Magic Mountain Prospect

We will commence drilling a 12,000 foot well to test our exploration target in the Ventura basin of Los Angeles County during the first half of 2001. The prospect contains the same Miocene-Age sands as those of a neighbouring field that had significant oil and gas production. The prospect is not subject to the Aera Agreement. We own a 100% working interest in the prospect.

Primex/Aera Exploration Agreements

On September 15, 1999, we entered into an agreement with Prime Natural Resources, LLC (formerly Prime-X Oil & Gas LLC) ("Primex") to jointly conduct a 3-D seismic survey in the southern San Joaquin Basin in order to identify new oil and gas prospects over an area of approximately 80,000 acres.

Effective October 1, 1999, we entered into an exploration agreement with Primex and Aera in which we agreed to pool certain of our respective acreage positions in the southern San Joaquin Basin in order to share the costs of carrying out the program and broaden our respective interests in the area. Aera will retain an equal interest in the data generated from the 3-D seismic program, but all costs of carrying out the program will be borne equally by Primex and ourselves.

The pooled acreage under the agreement is divided into four areas and our participating interest ranges from 17.5% to 50%. The survey is intended to identify prospects for exploration drilling. Once prospects have been identified, each party may elect to participate in a drilling program.

Texas Properties

In April, 2000, we entered into an agreement with Discovery Operating, Inc. ("Discovery") an independent oil and gas company. Discovery holds certain leases and is a party to certain farm-out agreements relating to over 9,100 gross acres of oil and gas exploration property in the Spraberry Trend of the West Texas Permian Basin in Midland County. Under the terms of our agreement with Discovery,

we hold, until payout of our costs, a 62.5% working interest in the property. Upon payout, we will retain a 50% interest. Discovery is the operator of the project. We have drilled 22 wells on the property to date, and 19 of the wells are now producing approximately 500 barrels of oil equivalents per day. During the remainder of 2001, we expect to drill an additional 30 wells on the property, and, by the end of 2001, to have approximately 49 wells on production. Ninety new wells will be required to develop our proved acreage in the Spraberry Trend. We have the option to continue or terminate the drilling program on a well-by-well basis.

In December, 2000 and during the first quarter of 2001, we acquired over 28,400 gross (20,700 net) acres in the Bossier gas sands, located in East Texas. We have identified six prospects where we expect to commence drilling in the third quarter of 2001. Our working interest in the Bossier sands is subject to leasehold burdens and a 9.375% net profit interest. We intend to continue increasing our leased acreage in the Bossier area.

China Properties

We hold interests in China through Sunwing. We acquired all of the issued and outstanding common shares of Sunwing in June, 1999 pursuant to a statutory arrangement under the *Yukon Business Corporations Act*.

Dagang Project

Our principal asset in China is a production sharing contract dated September 8, 1997 (the "Dagang Contract") with CNPC. PetroChina Company Limited ("PetroChina"), a subsidiary of CNPC, administers the Dagang Contract on CNPC's behalf. The Dagang Contract is a production sharing arrangement covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the "Dagang Project").

The Dagang Contract is effectively a licensing arrangement in which we are obliged to meet 100% of the development costs for which we receive the right to operate the Kongnan oilfield for a period of 20 years and participate in the oil production from the field. If and when we commence production at the Dagang Project, after deduction of royalties, value added tax and operating costs, we will be entitled to 82% of the remainder of the net revenue generated from oil production until our development costs have been recovered in full. Thereafter, we will be entitled to receive 49% of the net revenue.

We have a marketing arrangement with CNPC whereby we have the option of either exporting our share of oil production or selling it to CNPC. We currently sell our crude oil to CNPC at a price equal to the three month rolling average price of Cinta crude oil as published by Platts. The average price of Cinta crude oil over the last three years is approximately $2.00 per barrel less than the West Texas Intermediate ("WTI") price.

We are obliged to pay value added tax of 5% on oil production from the Dagang Project. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang Project exceeds 500,000 tonnes. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. We do not expect to pay royalties as we do not expect that any of the blocks will produce more than 500,000 tonnes per annum. Our entire interest in the Dagang Project will revert to CNPC if we terminate the Dagang Contract at the conclusion of the pilot testing phase, or at the end of the 20-year production period. We may elect to abandon the project at any time before the end of the 20-year production period.

We have farmed out a 20% working interest in the Dagang Contract to Nippon. Nippon earned its working interest by funding $6 million of pilot testing expenditures on the Dagang Project. We remain the operator of the Dagang Project.

In February, 2001, we completed the pilot testing phase and we are now preparing to submit an overall development plan for the Dagang Project to CNPC, for its approval during the third quarter of 2001. The

development phase will start after CNPC approval. We contemplate drilling approximately 120 new wells and reworking approximately 50 to 82 existing wells. We estimate that, in order to complete the development phase, we will need to invest in excess of $150 million over four years.

Daqing Project

We are also a party to a production sharing contract dated August 8, 1996 with CNPC (the "Daqing Contract") which covers an area of 8,100 gross acres in the Zhaozhou oilfield in Daqing, Heilongjiang Province, China (the "Daqing Project"). PetroChina also administers the Daqing Contract on CNPC's behalf.

The terms of the Daqing Contract are substantially the same as the Dagang Contract except we will be entitled to 85% of the net revenue from oil production until we have recovered our development costs. Our royalty payment obligations are the same as for the Dagang Project except that royalties are calculated on the basis of production from the entire project instead of individual blocks. CNPC is also entitled to a 2.5% priority allocation of oil production from the Daqing Project.

Like our marketing arrangement at Dagang, we have the option of either exporting our share of oil production or selling it to CNPC. We currently sell our Daqing Project crude oil to CNPC at a price equal to the three month rolling average price of Daqing crude oil as published by Platts. The average price over the last three years is approximately $1.50 per barrel less than the WTI price.

We successfully completed our pilot testing program in 1998. However, we delayed preparation of our overall development plan due to low world oil prices and in order to concentrate our efforts on the larger Dagang Project. CNPC agreed to operate the field pending their review and approval of our overall development plan for the Daqing Project. CNPC approved our overall development plan in February 2001 and, as a result, we expect to resume control of Daqing Project operations during the first half of 2001. Our overall development plan contemplates the drilling of approximately 60 new wells during a two year development phase which is scheduled to begin in the second half of 2001. We estimate that, in order to complete the development phase, we will need to invest approximately $23 million over two years.

Sichuan Basin

In February, 2001, we signed two memoranda of understanding with PetroChina. These memoranda give us the exclusive right to negotiate petroleum contracts with PetroChina in three land blocks in Sichuan Province.

We have agreed with PetroChina to carry out joint feasibility studies on the Zitongxi, Zitongdong and Yudong blocks located in the Sichuan Basin, approximately 930 miles southwest of Beijing. These blocks cover an area of approximately 2.2 million acres. If the results of the joint feasibility studies are positive, we will proceed to negotiate production sharing contracts, subject to Chinese government approvals. We will have the exclusive right to negotiate production sharing contracts with PetroChina for a period of four months following receipt of government approval in respect of the Yudong block and for a period of nine months from February 2001 in respect of the Zitongxi and Zitongdong blocks.

PetroChina has drilled 39 wells on the three blocks. Twenty-six of these wells have been classified as producing gas wells. PetroChina has only production tested eight of the estimated 38 hydrocarbon bearing structures located on the three blocks.

Russia Properties

When we commenced business in 1996, our original business plan was to acquire, explore, develop and operate oil and gas projects in Russia. We acquired a 50% interest in an exploration and development project at the Kalchinskoye field in western Siberia ("Tura"), a 50% interest in an exploration block adjacent to Tura ("Radonezh") and a 50% interest in an enhanced oil recovery project in the Krasnodar

region near the Black Sea. In 1998, we concluded that the Krasnódar project was uneconomic and we relinquished our interest in it.

We enjoyed greater success with our development and rehabilitation activities at Tura and succeeded in tripling production over an 18 month period. We curtailed investment under our development program at Tura in the second quarter of 1998 when our Russian partner in the Tura project, OJSC Tyumeneftegaz, and its parent company Tyumen Oil Company commenced a series of actions against us in the Russian courts seeking to deprive us of our interest in Tura. We also suspended our exploration program at Radonezh. Following almost two years of legal proceedings in the Russian courts and international arbitration proceedings in Stockholm, we reached a settlement in August, 2000 under which we received approximately $29 million in cash and divested all of our remaining Russian project interests. See Item 3. "Legal Proceedings".

Peru Properties

In August, 1998, we acquired a 50% participating interest in a 2.5 million acre concession in the Ucayali basin of east-central Peru known as Block 71 by funding $13.5 million in drilling and related expenditures. Our initial exploratory well on Block 71 was plugged and abandoned as a dry hole in December, 1998. The well, drilled to a total depth of 7,123 feet, encountered minor shows of oil and gas at various intervals, but was determined to be non-commercial. We relinquished our interest in Block 71 during 2000.

COMPETITION

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for, and development of, new sources of supply, is particularly competitive. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors."

ENVIRONMENTAL REGULATIONS

Both our oil and gas and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. We believe that our operations comply in all material respects with applicable environmental laws.

In the United States, environmental laws and regulations are implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

In Australia, operations are subject to regulation under various state, territory and commonwealth (federal) environmental laws. At the federal level, the Department of Primary Industry and Energy has regulatory responsibility. This responsibility is shared at the state/territory level with the Department of Minerals and Energy. Various environmental protection agencies provide advice to these departments.

GOVERNMENT REGULATIONS

Our business is subject to certain United States and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various

aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years in the United States, often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

At March 1, 2001, we had 70 employees. None of our employees are unionized.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities included under Item 8 in this Annual Report for information with respect to our oil and gas producing activities. We have not filed with or included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average production costs per unit of production. Average sales prices are after royalties in the United States and Russia. In China, proceeds from the sale of oil produced is credited to our China cost pool due to the stage of development of our projects in China. In 2000, the average sales price realized on China production was $28.26 (1999 — $21.27). Average production costs include lifting costs, but exclude depreciation, depletion and amortization, royalties, income taxes, interest and selling administrative and other expenses.

	Average Sales Price			Average Production Cost		
	2000	1999	1998	2000	1999	1998
Crude Oil and Natural Gas Liquids ($/Boe)						
Russia	—	$ 4.68	$ 7.43	—	$ 2.49	$ 2.86
United States	$27.52	—	—	$10.00	—	—

The following tables set forth the number of productive crude oil wells (both producing wells and wells capable of production) in which we held an interest at December 31, 2000 and 1999:

	2000		1999	
	Oil		Oil	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Russia	—	—	—	—
United States	29	25.6	—	—
China	9	6.7	4	3.4

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

The following table sets forth, for each of the last three fiscal years, our participation in the drilling of net crude oil and natural gas wells

Exploratory

	Productive		
	2000	1999	1998
Russia	—	—	0.5
United States	—	—	—
China	—	—	—
Total	0	0	0.5

	Dry		
	2000	1999	1998
Russia	—	—	1
United States	2	2	—
China	—	—	—
Total	2	2	1

Development

	Productive		
	2000	1999	1998
Russia	—	—	2
United States	25.6	—	—
China	3.3	3.4	—
Total	28.9	3.4	2

	Dry		
	2000	1999	1998
Russia	—	—	—
United States	2	—	—
China	—	—	—
Total	2	0	0

The following tables set forth our holdings of developed and undeveloped oil and gas acreage at March 1, 2001:

	Developed		Undeveloped	
	Gross Acres(1)	Net Acres(2)	Gross Acres(1)	Net Acres(2)
United States	2,465	1,864	117,338	68,026
China(3)	1,976	927	28,479	13,356

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

(3) The number of developed acres disclosed in respect of our China projects relates only to those portions of the relevant fields covered by our pilot testing operations and does not include the remaining portions of the fields previously developed by CNPC.

As of March 1, 2001 we were in the process of drilling one well in Texas. A total of five wells were started in Texas in 2001, four of which reached total depth by March 1, 2001 and will be completed and put on production in due course.

The following table sets out estimates of our share of proved reserves in respect of our United States and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2000. Estimates for our China operations were prepared by independent petroleum consultants Gilbert Laustsen Jung Associates Ltd. Estimates for our United States operations were prepared by independent petroleum consultants Duke Engineering & Services and Joe C. Neal & Associates.

	Our Share		Our Share of Before Tax Cash Flows in thousands of dollars discounted at:			Our Share of After Tax Cash Flows in thousands of dollars discounted at:		
	OIL	GAS						
	(MBbl)	(MMcf)	0%	10%	15%	0%	10%	15%
Proved Reserves(1)								
United States	4,773	6,296	$ 67,604	$ 28,133	$ 19,501	$ 46,103	$ 19,202	$ 13,585
China	21,021	—	278,287	120,687	83,411	196,954	82,034	54,989
	25,794	6,296	$345,891	$148,820	$102,912	$243,057	$101,236	$ 68,574

(1) "Proved Reserves" are the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. Our share of the reserves is shown before royalties. Our share of the reserves net of royalties is disclosed in the "Supplementary Disclosures about Oil and Gas Production Activities", which follow the notes to our financial statements set forth in Item 8 of this Annual Report.

ITEM 3. LEGAL PROCEEDINGS

We jointly formed Tura with TNG in 1996, through a Russian closed stock company, to enhance production at the Kalchinskoye oil field in the Tyumen Region of western Siberia. At that time, the Russian government held a controlling interest in TNG's parent Tyumen Oil Company. During 1997 and the first half of 1998, we achieved substantial technical success at the Tura Project. Our introduction of western capital and technology to the project resulted in daily production at the field more than doubling, from 4,900 barrels of oil per day to 11,500 barrels of oil per day.

In May, 1998, shortly after the privatization of Tyumen Oil Company, its new owners began to assert direct management control over TNG and began to dispute the terms of our Tura joint venture. They then commenced a number of legal actions against the Tura joint venture company in the Tyumen regional courts challenging the validity of the foundation agreement which created the Tura joint venture company and the transfer from TNG to the Tura joint venture company of the licenses required to develop the Kalchinskoye oil field.

In their initial series of court actions, TNG and Tyumen Oil Company obtained temporary injunctions against the Tura joint venture company. These injunctions did not materially affect production, but severely restricted Tura's ability to sell its oil during the second half of 1998. In the face of TNG's actions, we withheld planned capital contributions to the Tura project for further development of the field and limited Tura's operations to maintenance activities. In early 1999, Tura succeeded in negotiating an interim sales agreement with Tyumen Oil Company, with the assistance of the Russian Ministry of Fuel and Energy. This agreement facilitated the sale of 1998 year end inventory as well as production through the second quarter of 1999. While the terms of the agreement were unfavourable to Tura, oil sales produced cash flow which allowed Tura to maintain oil field operations while the dispute continued. This interim agreement expired in June, 1999.

Throughout the dispute, Tura was involved in a series of legal proceedings with TNG and Tyumen Oil Company in the Russian courts, both at the regional level in Tyumen and at the appellate level in the senior courts in Moscow. Although we argued that the Russian court decisions were procedurally flawed and legally incorrect, TNG and Tyumen Oil Company prevailed in certain key judicial decisions and were ultimately successful in effectively invalidating the Tura foundation agreement and the license transfers. TNG was subsequently able to obtain new licenses for the Kalchinskoye field which superseded Tura's

licenses. As a consequence, Tura's direct production and oil sales rights were revoked and, as of June 1999 the Tura joint venture company was replaced as operator of the field.

In June, 1999, we commenced international arbitration proceedings against TNG under the authority of the Chamber of Commerce of Stockholm, Sweden pursuant to the UNCITRAL Arbitration Rules. We alleged that TNG willfully and materially breached numerous provisions of the Tura joint venture company's charter and acted in bad faith and in willful disregard of its contractual obligations. Through the arbitration, we sought an award of approximately $110 million representing, among other things, recovery of our investment and lost future profits.

In August, 2000, we entered into a settlement agreement with TNG, Tyumen Oil Company and Stesana Enterprises Limited ("Stesana"). Under the terms of the settlement agreement, we disposed of all of the outstanding shares of the two Cypriot subsidiaries through which we held our interest in Tura and in the adjacent Radonezh exploration project. As consideration, we received approximately $29 million in cash from the acquiror, Stesana. We also agreed with TNG and Tyumen Oil Company to terminate all legal proceedings in Russia and all proceedings in connection with the Stockholm arbitration. All such proceedings have now been terminated.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares are traded on the NASDAQ National Market and The Toronto Stock Exchange.

The high and low sale prices of our common shares as reported on the NASDAQ National Market for the third and fourth quarter of 2000 and The Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ NATIONAL MARKET (IVAN)

	2000			
	1st Q	2nd Q	3rd Q(1)	4th Q
High	—	—	4.6875	6.75
Low	—	—	4.00	3.875

(1) Our common shares did not commence trading on the NASDAQ National Market until August 28, 2000.

THE TORONTO STOCK EXCHANGE (IE)
(CDN.$)

	2000				1999			
	1st Q	2nd Q	3rd Q	4th Q	1st Q	2nd Q	3rd Q	4th Q
High	4.20	7.20	7.50	9.80	0.60	2.20	4.90	3.95
Low	2.50	2.61	5.95	6.00	0.32	0.43	2.10	2.50

On March 1, 2001, the closing prices for our common shares were $4.6875 on the NASDAQ National Market and Cdn.$7.15 on The Toronto Stock Exchange.

Holders of Common Shares

As at March 1, 2001, a total of 127,047,362 of our common shares were issued and outstanding and held by 89 holders of record.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or would after payment of the dividend be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the "Investment Act"), which generally prohibits a reviewable investment by an entity that is not a "Canadian", as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a "WTO investor" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value of our assets, as determined under Investment Act regulations, was Cdn.$5,000,000 or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. An investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2001 is Cdn.$209 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-United States Income Tax Convention (the "Convention"). Currently, under the Convention, the rate of Canadian

non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation which owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax exempt entities which are residents of the United States for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements which form part of this Annual Report. The financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") applicable in Canada which is not materially different from GAAP in the United States. For a United States GAAP reconciliation, see Note 14 to our financial statements. See also Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation".

The following table shows selected financial information for the periods indicated:

	Year ended December 31,				
	2000	1999	1998	1997	1996
	(stated in thousands of U.S. dollars, except per share amounts)				
Revenues	$14,063	$ 6,210	$ 12,752	$ 15,077	$ 24
Total assets	99,800	47,659	49,442	120,483	22,752
Long-term debt	Nil	Nil	1,763	1,718	Nil
Net earnings (loss)	5,429	(7,802)	(70,677)(1)	(2,185)	(1,593)
Net earnings (loss) per share	0.05	(0.08)	(0.79)	(0.03)	(0.22)

(1) Includes asset writedown of $70.2 million. See Note 9 to our financial statements under Item 8 in this Annual Report.

Reconciliation to GAAP in United States

Our financial statements have been prepared in accordance with GAAP applicable in Canada which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the United States. The only material difference between Canadian and U.S. GAAP which affects our financial statements is that under U.S. GAAP the determination of earnings per share is calculated excluding shares held in escrow, and dilutive earnings per share is calculated on the treasury method rather than the imputed earnings method applied in Canada.

Had we followed U.S. GAAP, certain selected financial information reported above would have been reported as follows. Potential exercise of the stock options and warrants disclosed in Note 7 to the financial statements and potential conversion of the debt, Note 6, do not have a material dilutive effect on the earnings per share.

	Year ended December 31,				
	2000	1999	1998	1997	1996
	(stated in thousands of U.S. dollars, except per share amounts)				
Net earnings (loss) per share	0.05	(0.09)	(1.10)	(0.04)	(0.22)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Year Ended December 31, 2000

Overview

During 2000, we concentrated our efforts on developing drillable prospects in the San Joaquin Valley of California on acreage covered by the Aera Agreement and on additional acreage we acquired there. To date, we have identified six drillable prospects. We have selected a location for our first deep-gas well at Northwest Lost Hills and, depending on rig availability, we plan to spud the well during the second quarter of 2001. During the second quarter of 2000, we commenced a drilling program in the South Midway Sunset area and, by year-end, we had drilled 21 wells. We commenced commercial production during the third quarter. See Items 1 and 2. "Business and Properties — Oil and Gas Properties — California Properties".

In 2000, we secured a 62.5% interest (96% interest in the first four wells) in 9,100 gross (5,700 net) acres in the Spraberry Trend of the West Texas Permian Basin. By year-end, we had spudded 16 wells. Our interest in the play decreases to 50% after payout. During the fourth quarter of 2000 and the first two months of 2001, we acquired an interest in over 28,400 gross (20,700 net) acres in the Bossier sands in East Texas, where we expect to commence drilling in the third quarter of 2001. See Items 1 and 2. "Business and Properties — Oil and Gas Properties — Texas Properties".

At our two projects in China, we concentrated our efforts on completing the pilot testing phase of the Dagang Project and obtaining approval by the Chinese government for our overall development plan at our Daqing Project, which we received in February, 2001. Implementation of the plan is scheduled to commence in the third quarter of 2001. At our Dagang Project, the pilot testing phase was completed successfully in February 2001. We now plan to proceed with the development phase which will require the submission of an overall development plan to the Chinese government for approval. We expect to submit it in the second half of 2001. See Items 1 and 2. "Business and Properties — Oil and Gas Properties — China Properties".

During 2000, we acquired a master license from Syntroleum permitting us to use Syntroleum's proprietary GTL technology and on October 5, 2000 we signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project under development in Western Australia. See Items 1 and 2. "Business and Properties — Gas-to-Liquids Projects."

In August, 2000 we were successful in negotiating a settlement of our legal dispute with our Russian partner at Tura in Western Siberia. In consideration for relinquishing our entire interest in Tura and the adjacent Radonezh Project, we received $28.2 million, net of settlement and severance costs of $0.8 million. See Item 3. "Legal Proceedings".

Operations

Our net income for the year was $5.4 million ($0.05 per share) compared to a loss in 1999 of $7.8 million ($0.08 per share). We attribute the improvement from 1999 to the commencement of initial production from our properties in California and Texas and from the gain of $12.2 million we realized from the settlement of our Russian dispute. Our cash flow deficiency for the year ended December 31, 2000 was $11.8 million, up 90% from the cash flow deficiency of $6.2 million we experienced in 1999. In 2000, we raised $47.7 million through private placements and exercise of warrants and incentive stock options ($0.7 million in 1999) and invested $40.8 million ($10.7 million in 1999) in capital assets. By the end of 2000, we were able to sell, without further loss, the last of our equipment originally destined for Russia.

Production

In 2000, we commenced production at our South Midway Sunset field in California and at our Spraberry field in West Texas. At South Midway Sunset we drilled and completed our first well and went into production in July 2000. By year-end we had drilled a total of 21 wells of which 19 were completed and 17 in production. The remaining two completed wells were placed on production in January 2001. The two uncompleted development wells were dry, one of which we plan to use as a water disposal well. At the Spraberry Trend, we drilled 16 wells in 2000, of which 10 were completed and on production by year-end, with the remaining six wells completed and placed on production in early 2001. To date in 2001, we have drilled an additional six development wells, of which one was placed on production in February, 2001.

Production and revenues we generated in 2000 are detailed below. Although we generated production revenue in 1999 and 1998, it was all attributable to our former Russian operations and, as a consequence, is not comparable.

	2000		
	Midway	**Spraberry**	**Total**
Net Production			
Oil — Bbls	19,096	10,981	30,077
Gas — Mcf	—	4,816	4,816
Boe	19,096	11,833	30,929
Boe per day — exit rate December 31, 2000	253	383	636
Per Boe			
Average sales price	$25.39	$30.96	$27.52
Operating costs	13.56	4.25	10.00
Production taxes	—	1.50	0.57
	13.56	5.75	10.57
Depletion, Depreciation and Amortization			8.70
			19.27
Net			$ 8.25

Total revenue from our oil and gas operations was $851,000. Our operating costs at South Midway Sunset were unusually high due to facility rental costs associated with start-up operations. We expect to reduce our operating costs at South Midway Sunset to the $4.00 per barrel range during the second quarter of 2001. Operating costs we reported in our statement of income include allocated head office engineering support costs of $0.5 million. Depletion, depreciation and amortization costs are high due to the nature of the South Midway Sunset and Spraberry Trend projects. While South Midway Sunset and Spraberry Trend require high development and facility costs to exploit limited reserves, both provide good economic returns at current oil and natural gas prices.

Project Identification Costs

We remain committed to the geographical diversification of our oil and gas activities. We follow the practice of expensing the costs we incur in pursuing and investigating new projects. With the acquisition of our Syntroleum master license, we have intensified our search for new international oil and gas and GTL projects. During 2000, we incurred $3.7 million, up $2.0 million from the $1.7 million incurred in 1999, in costs associated with international project opportunities that we have rejected or that we were still investigating at year-end. Once we obtain rights or interests in a new project we capitalize the costs we incurred in obtaining the project.

General and Administration

We incurred general and administrative costs of $2.8 million during 2000, up $0.2 million from the $2.6 million we incurred in 1999. We attribute the bulk of the increase to the costs associated with listing on NASDAQ in 2000.

Other Income and Expenses

Interest income represents income we earned on our excess cash balances held during the year. The increase of approximately $0.5 million during 2000 arises from the additional funds available from two private placements we completed during the year and from the divesture of our Russian projects. Russian litigation costs (down approximately $0.3 million from 1999), depletion and depreciation (down $1.3 million from 1999) and asset write downs (down $2.5 million from 1999) all result from the divesture of our Russian projects and the settlement of our legal dispute with our Russian partner in August 2000.

Income Taxes

We have significant tax losses available to carry forward and reduce taxes otherwise payable. Given the uncertainty as to the utilization of these tax loss carry-forwards, we have followed the practice of recording a provision against the tax benefit asset resulting from these losses. In 2000, our expected income tax expense on the income reported on our statement of income has been reduced by the benefit of tax assets not previously recorded.

Exploration and Development Activities

During 2000, we carried out an extensive exploration program in the San Joaquin Valley on acreage primarily acquired under our Aera Agreement. We participated in an 80,000 acre 3-D seismic shoot, the largest ever carried out in the San Joaquin Valley. We purchased an additional 7,000 acres of 3-D seismic previously shot in the same area. We also continued interpreting over 2,000 miles of 2-D seismic acquired in 1999. We submitted preliminary prospects to Aera for its review in 14 areas covered by the Aera Agreement. We are developing numerous drillable prospects within those preliminary prospect areas and, during 2000, we submitted six drillable prospects to Aera. See Items 1 and 2. "Description of Business and Properties — Oil and Gas Properties — California Properties — Aera Agreement". At South Midway Sunset, where we have a 100% interest, we commenced a drilling program, details of which are discussed above under "Production". In addition to the South Midway Sunset drilling program, we drilled three other exploration wells in the San Joaquin Valley during 2000, two of which were dry and abandoned. We are still testing the third well to determine its commercial potential. We identified the location of our first deep gas well at Northwest Lost Hills and we expect to spud the well during the second quarter of 2001.

In Texas, we drilled 16 successful wells in our Spraberry Trend acreage in West Texas by year-end and an additional four wells during the first two months of 2001. Through a series of transactions in late 2000 and early 2001, we were successful in acquiring an interest in over 28,400 gross (20,700 net) acres in the Bossier gas sands in East Texas. We expect to commence drilling at Bossier during the third quarter of 2001.

At our Dagang Project in China, we completed our pilot testing phase in February, 2001. During 2000, as part of the pilot testing phase, we placed in production four new wells. We placed our initial well on water injection late in 2000 to evaluate the waterflood potential of the field. We also placed on production a fifth well in early 2001. We have decided to proceed to the development stage of our Dagang Project, which will require the submission of an overall development plan to the Chinese government for approval. We expect to submit it to the Chinese government during the second half of 2001. In the interim, we will continue to operate the pilot wells with production revenue accruing to us. At our Daqing Project, our overall development plan was approved in February, 2001 and we expect to start implementing it during the third quarter of 2001. Although we completed the pilot testing phase of

the Daqing Project in 1998, we delayed submitting our overall development plan to the Chinese government because of low world oil prices and in order to focus our attention on our Dagang Project. In the interim, we agreed with CNPC to temporarily cede our operatorship of the Zhaozhou field pending completion and approval of our overall development plan for the Daqing Project. Having submitted and received approval for the Daqing Project, we expect to resume our role as operator during the first quarter of 2001.

The following summarizes the production and revenue we realized from the pilot testing phase of our Dagang Project. Prior to deciding to proceed to the development phase, this revenue was credited to the China cost pool for accounting purposes. All sales of oil are at or about WTI less approximately $2.00 for quality and transportation. We receive all proceeds in U.S. dollars offshore China.

	2000	1999
Oil production (net) — Bbls	102,708	4,334
Price per Bbl realized	$ 28.26	$ 21.27
Total proceeds	$2,903,000	$92,203

Our total capital spending on oil and gas operations during 2000, compared to 1999, was as follows:

	2000	1999
	(in thousands)	
Capital Expenditures:		
United States	$22,816	$ 9,565
China	5,676	13,280
Russia	—	1,283
Peru	—	80
	$28,492	$24,208
Comprised of:		
Property acquisition	$ 6,392	$11,346
Royalty acquisition	1,157	4,023
Seismic	3,840	3,442
Exploration	667	1,311
Development	19,376	4,178
	31,432	24,300
Less: China oil production	(2,940)	(92)
	$28,492	$24,208

Gas-to-Liquids

During 2000, we acquired a master license from Syntroleum which allows us to use Syntroleum's proprietary GTL technology in an unlimited number of GTL projects throughout the world excluding North America, China and India. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop cleaner-burning diesel fuel and other synthetic petroleum products. We have commenced engineering studies and review of several potential sites for our first GTL plant and we are in advanced discussions with national petroleum corporations in the Middle East and Asia.

On October 5, 2000, we signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project under development in Western Australia. The plant, which will be located on the Burrup Peninsula in Western Australia, will convert natural gas contracted from the North West Shelf Venture Partners into ultra clean synthetic specialty products, such as lubricants, industrial fuel and paraffins, as well as synthetic fuels. See Items 1 and 2. "Business and Properties — Gas to Liquids Projects."

Liquidity and Capital Resources

We intend to pursue an aggressive capital expenditure program throughout 2001.

At Spraberry and at South Midway Sunset we plan to continue our ongoing development programs. During 2001 we expect to drill nine development wells per quarter at Spraberry and an additional six development wells at South Midway Sunset. We consider both Spraberry and South Midway Sunset to be low risk, low cost projects which should continue to provide good economic returns at current commodity prices. Should prices weaken, we will review our development program and adjust to either delay or curtail our activities on these projects.

Our exploration activities during 2001 will be concentrated in Southern California and in the Bossier sands. We plan to spud our first deep gas exploration well at Northwest Lost Hills during the second quarter. We may also drill up to five additional exploration wells in the San Joaquin and Ventura Basins during the balance of the year, subject to rig availability and funding.

In China, we will focus our 2001 activities on submitting a full development plan for our Dagang project to CNPC during the third quarter, and on initiating our development plan at the Daqing project. Although we expect Daqing to be more capital intensive during 2001 than Dagang, we have the ability to extend the development of Daqing over a three year period if necessary. All income derived from production from the pilot test wells at Dagang and Daqing during this period will be for our account.

We expect that Syntroleum will be successful in arranging project financing for the Sweetwater GTL project in Australia before the end of 2001. Once Syntroleum arranges project financing, we will be required to complete our acquisition of a 13% equity interest in the project by remitting $19 million. Since GTL project development is our long-term core strategy, we will continue to actively pursue opportunities to construct GTL conversion plants on top of existing stranded gas fields.

For 2001, we have budgeted approximately $66 million for drilling and development plus an additional $19 million for the Sweetwater project. Planned capital expenditures may increase if we are successful in acquiring an additional GTL project during 2001 but we can give no assurance that we will do so.

At December 31, 2000, we had $29.7 million in cash. Other than a $1 million convertible debenture, we have no outstanding debt. We have not previously pursued any credit facilities due to our success in raising capital through the sale of equity securities. However, we can give no assurance that this source of funding will continue to be available in the future.

Excluding any additional capital expenditures we may incur if we acquire an additional GTL project during 2001, we will require external financing, net of existing financial resources and internally generated cash flow, of approximately $45 million to carry out all our planned activities, including overhead and the pursuit of new opportunities. Although we intend to raise the funds we need through the sale of equity securities or from production loans secured against our producing properties, we can give no assurance that we will be successful in doing so. If we are unable to raise the necessary funds, we will have to prioritize our activities, which may result in delaying, and potentially losing, some valuable business opportunities. Any such delay or loss may have a material adverse effect on our ability to successfully implement our corporate strategy.

Year Ended December 31, 1999

Overview

During 1999, we continued to increase the overall size of our land position in the San Joaquin Valley of California through acquisitions. We purchased Diatom, a holder of extensive exploration rights in the area. We also acquired a series of royalty interests in the same area. We intend to continue adding to our oil and gas interests in the San Joaquin Valley whenever attractive opportunities arise.

In June, 1999, we acquired Sunwing by issuing approximately 17.5 million of our common shares to Sunwing's former shareholders. Through Sunwing, we hold two production sharing agreements with CNPC

which entitle us to participate in development projects in two of China's largest oil producing regions and we have acquired the services of Sunwing's senior management personnel who have excellent technical credentials and good working relationships with CNPC and the relevant Chinese government ministries and agencies.

Throughout 1999, the status of our investment in the Tura project in Russia remained unresolved. TNG, our partner in the Tura Project, and its parent, Tyumen Oil Company, assumed effective control of the project in June, 1999. TNG continued its efforts in the Russian courts to deprive the Tura joint venture company, through which we hold our interest in the project, of its oilfield assets and equipment, without compensation, and to obtain a reimbursement of revenues received by the Tura joint venture company from prior oilfield production. To that end, TNG obtained judgement against the Tura joint venture company and a writ of execution for the sale of its assets. An auction of the assets was held on May 16, 2000. No bids were received and, consequently, the bailiff transferred equipment worth 256 million rubles (approximately US$9.23 million based on then prevailing currency exchange rates) to TNG in settlement of its claim against the Tura joint venture company. We continued to pursue avenues of appeal in the Russian courts seeking to obtain a satisfactory remedy through Russian legal proceedings. We also initiated international arbitration proceedings in Stockholm, seeking recovery of our investment and lost future profits.

Based on the uncertain status of our investments in Russia (including our investment in the Radonezh project, which was not under legal challenge but was suspended pending resolution of the Tura dispute, and certain equipment owned by our Cypriot subsidiaries), we stopped proportionately consolidating the results of our Russian operations with our other operations for financial reporting purposes as at June 30, 1999. After June 30, 1999, we recorded our investments in the Russian projects at cost, less an impairment provision we made as at December 31, 1998 in accordance with GAAP. We capitalized all costs, other than legal costs, associated with these investments, and amounts we recovered were applied to reduce the carrying value of the investments.

For financial statement presentation in 1999, we assumed that we would be successful in reaching a negotiated settlement of the dispute sufficient to recover the recorded carrying value of our investment in the Russian projects.

As at December 31, 1999, we recorded the remaining value of our investment in Russian operations at $16.2 million. This amount represented the residual value of our investment in the Russian projects, after providing for impairment of $46.7 million in 1998, plus $442,000 in costs we incurred during 1999 to maintain a presence at the Tura site after we lost control of field operations, less direct remittances of $2.9 million we received from the Tura joint venture company as proceeds from the sale of oil, excess supplies and equipment.

Operations

In 1999, we lost $7.8 million ($0.08 per share), including $2.5 million for impairment of equipment held for resale, compared to a loss of $70.7 million ($0.79 per share), also including a provision for impairment of oil properties and equipment held for resale of $70.2 million, during 1998. Our cash-flow deficiency from operating activities during the year was $6.2 million, compared to positive cash flow from operating activities of $4.7 million during 1998. In 1999, we received $735,000 as the proceeds of the issuance of common shares pursuant to the exercise of stock options and we invested cash of $10.7 million in capital assets ($30.1 million in 1998). In 1999, we realized $4.3 million from the sale of equipment we originally intended to use at the Tura project but retained and sold after the Tura project dispute arose. As of December 31, 1999 we held an additional $3.3 million of equipment for sale.

During the period from January to June, 1999, when we lost control of the Tura project, we incurred a loss of $222,000 in respect of our Russian operations. From January until June, 1999 our share of production from the project was 806,679 barrels of oil (4,980 barrels per day, compared to 4,995 barrels per day during 1998). Our share of oil sales in 1999 was $5.5 million (representing 1,167,289 barrels at an average price of $4.68 per barrel), primarily into Russian domestic markets, compared to $11.0 million

($7.43 per barrel) received during 1998. This reduction in oil revenue of $5.5 million resulted from reduced volumes of oil (310,00 barrels) being available for sale as a consequence of our loss of operational control in June, 1999. Depressed domestic oil prices in Russia were also a factor because, as a result of TNG's litigation against the Tura joint venture company, TNG was able to force Tura to sell all of its oil in Russian domestic markets. Our operating cost per barrel in 1999 dropped to $2.49 per barrel, a decrease of $0.37 per barrel from that incurred in 1998, primarily as a result of reducing our staff and activity levels. Sales in 1999 were primarily in the domestic Russian market and, as a consequence, transportation costs and excise taxes, which are levied on export sales only, were reduced from the 1998 levels of $0.90 and $1.88 by $0.70 per barrel and $0.96 per barrel, respectively. Depletion per barrel during 1999 amounted to $2.00 compared to $3.04 per barrel, before provision for impairment, in 1998. In addition, Tura recovered operating costs for the month of June when all production was for the account of TNG. Our share of this additional revenue amounted to $296,000. All petroleum revenues reported in 1999, 1998 and 1997 were from our share of Tura's sales. Since June 1999, there have been no petroleum sales from the Tura project. Activities at the Tura project during the latter half of 1998 and most of 1999 consisted primarily of selling oil production, disposing of excess supplies and equipment and defending the numerous legal actions brought by TNG and its parent company, Tyumen Oil Company. For the period from June 30, 1999 to December 31, 1999, we incurred continuing costs of $442,000 to maintain our presence at the Tura project. These costs were partially offset by the $380,000 we received from Tura representing proceeds from the sale of excess supplies and equipment. In total, during 1998 and 1999 the Tura joint venture company was able to directly remit to us $2.4 million and $2.9 million, respectively, from proceeds received from the sale of oil, excess supplies and equipment.

We incurred general and administrative costs during 1999 of $5.3 million, which was $2.4 million more than we incurred during 1998. Although we incurred additional costs of approximately $500,000 in establishing our business in California and funding additional administrative costs we assumed when we acquired Sunwing, the bulk of the 1999 increase was attributable to additional legal and professional fees of $1.1 million incurred preparing our international arbitration claim in Stockholm and costs of $1.7 million incurred pursuing other project opportunities. For presentation purposes in the 2000 financial statements these latter two items have been reclassified and presented separately in the consolidated statement of income.

We incurred capital expenditures of $24.2 million during 1999 (including $13.4 million through the issue of common shares) to acquire Sunwing ($10.5 million), Diatom ($548,000) and certain overriding royalty rights ($4.0 million), to increase our land holdings in the San Joaquin Basin and to obtain additional technical information with respect to our California properties ($5.0 million), and to implement our Dagang Project's pilot testing program in China ($2.8 million). In addition, our share of capital expenditures incurred and funded by our Russian operations in early 1999, amounted to $1.3 million. The nature of the 1999 expenditures, compared to those in 1998 is as follows:

	1999 Capital Expenditures			1998 Capital Expenditures
	By Issue of Shares	Cash	Total	
	(in thousands)			(in thousands)
Property Acquisition				
Proved	$ 6,936	$ 532	$ 7,468	$ 100
Unproved	3,381	497	3,878	250
Royalty rights	3,163	860	4,023	—
Development	—	4,086	4,086	9,517
Exploration	—	4,753	4,753	20,191
	$13,480	$10,728	$24,208	$30,058

Risk Factors

We are subject to a number of risks due to the nature of the industry in which we operate, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may adversely affect our financial condition.

Since we lost effective control of our interest in the Tura project in Russia in 1999, we have only recently resumed generating limited revenue from the production and sale of oil. We have no sustained history of earnings and we have operated at a loss since we commenced business. We have relied, and continue to rely, on external sources of financing to meet our capital requirements, to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. In January and February 2000, we completed approximately $14 million in equity financing and in October 2000, we completed approximately $25 million in equity financing. We also received approximately $29 million in August, 2000 from the sale of our Russian project interests. We plan to obtain the future funding we will need through debt and equity markets, but we cannot assure you that we will be able to obtain additional funding when it is required. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties or default on existing funding commitments to third parties and forfeit our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

Our exploration and development properties may not contain any significant proven reserves beyond those disclosed in this Annual Report. Any forward-looking exploration, development and production cost data contained in this Annual Report are only estimates, and our actual production, revenues and expenditures may differ materially from these estimates.

We have not determined that materially significant proven reserves exist on any of our oil and gas properties beyond those disclosed in this Annual Report. Oil and gas exploration and development involves significant risks. Few wells which are drilled are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proven reserves, and there can be no assurance that commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs. Our estimates of exploration, development and production costs can be affected by such factors as permitting regulations and requirements, weather, environmental factors, unforeseen technical difficulties, and unusual or unexpected formations, pressures and work interruptions. We cannot assure you that actual exploration cost will not exceed projected cost.

Our business may be adversely affected if we are not able to retain our licenses, leases and working interests in licenses and leases.

Some of our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may have a material adverse effect on the results of our operations and business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are not able to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may have a material adverse effect on our business and results of operations.

Our operations may be adversely affected if we allocate significant financial resources to exploration of properties which do not contain any proven reserves. In addition, our operations may be affected by significant operating hazards and natural disasters.

We face a number of risks inherent in oil and gas exploration and development. Exploration activities are expensive and consume significant financial resources. Although we try to allocate our limited financial resources to those properties which we believe are most likely to yield a discovery, we can never be certain that our exploration activities on a particular property will be successful. Like other oil and gas exploration companies, we try to mitigate our exploration risk by conducting our activities jointly with other exploration companies through joint ventures and farm-in/farm-out arrangements. In carrying out our exploration activities, we are also vulnerable to adverse weather conditions, mechanical difficulties, delays in the delivery of equipment and the risk of fire, explosions and blow-outs.

We are not able to guarantee the successful commercial development of the GTL technology.

No commercial-scale GTL plants have yet been constructed using Syntroleum's proprietary GTL process and, therefore, the process has not been proven on a commercial scale. Other commercial developers of GTL technology include ExxonMobil, Shell and Sasol, each of which has significant financial resources and may be able to use its greater financial flexibility to commercialize their GTL technologies and commence production of GTL products earlier than we and Syntroleum can, thereby obtaining a potential competitive advantage. This advantage may prove to be particularly important as GTL project developers compete to obtain the most attractive stranded natural gas deposits to provide feedstock for their plants. The planned Sweetwater GTL plant requires significant project financing in order to come into production on schedule in 2003. See Items 1 and 2. "Business and Properties — Gas-to-Liquids Projects".

Our operations are affected by the volatility of prices for crude oil and natural gas.

As with most other companies involved in resource exploration, we may be adversely affected by future increases in the costs of conducting exploration, development and resource extraction which may not be fully offset by increases in the price received on sale of the crude oil or natural gas.

Our revenues, profitability and future growth, if any, and the value of our oil and gas properties are substantially dependent on prevailing prices of oil and gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of, and demand for, oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the value of our properties, our financing capacity and our prospects for commencing and sustaining any economic commercial production.

Over the last 10 years, oil prices have fluctuated from $10 to over $30 per barrel. During 2000 and the first quarter of 2001, oil prices have remained in the range of between $25 and $35 per barrel after experiencing a significant decline to a low of approximately $10 per barrel in 1997 due to the Asian financial crisis and other economic factors. Oil and gas prices could be significantly impacted if the Kyoto Protocol is enacted. The Kyoto Protocol requires Western countries, including the United States and Canada, to reduce the emission of hydrocarbons to below existing levels, increase the efficiency of the use of oil and its by-products and reduce consumption. In the long term, we expect oil prices to remain volatile.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have

difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

Government regulations in China and other foreign countries may limit our activities and adversely affect our business operations. The interpretation and enforcement of our contractual rights may be affected by the prevailing laws of the foreign jurisdiction.

We hold our interests in our China properties through production sharing contracts with CNPC. We also have two memoranda of understanding with CNPC's subsidiary, PetroChina, indicating a mutual intention to negotiate additional production sharing contracts. We may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed western legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

We cannot assure you, based on our existing memoranda of understanding with PetroChina, that we will successfully negotiate additional production sharing contracts. Although we enjoy a good relationship with CNPC in respect of our existing production sharing contracts, it is possible that disputes between us could arise in the future which must be resolved under foreign law. Foreign legal mechanisms for resolving legal and business disputes are not necessarily comparable to typical dispute resolution mechanisms used in Western countries. In China, previously decided cases are not necessarily binding in subsequent disputes, meaning that outcomes tend to be unpredictable. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

The cost of complying with governmental regulations in the United States and China may adversely affect our business operations.

We are subject to various federal, state, provincial and local government regulations in the United States and China. These regulations may change depending on prevailing political or economic conditions. In order to comply with these regulations, we may be required to obtain discharge permits for drilling operations, post-drilling and abandonment bonds and file reports concerning our operations. These regulations affect how we carry on our business and in order to comply with them we may incur increased costs and delay certain activities pending receipt or requisite permits and approvals. If we fail to comply with applicable regulations and requirements we may become subject to enforcement actions, including orders issued by regulatory or judicial authorities requiring us to cease or curtail our operations, take corrective measures involving capital expenditures, installation of additional equipment, or remedial actions. We may be required to compensate third parties for loss or damage suffered by reason of our activities, and may face civil or criminal fines or penalties imposed for violations of applicable laws or regulations. Amendments to current laws, regulations and permits governing our operations and activities could affect us in a materially adverse way and could force us to increase expenditures or abandon or delay the development of new oil and gas properties.

Our business operations may be adversely affected by present or future environmental regulations.

Oil and gas exploration, development and production operations are subject to varying degrees of environmental regulation in both China and the United States. Environmental legislation is evolving in a manner which imposes stricter standards and enforcement, increased fines and penalties for

non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their officers, directors and employees. Future changes in environmental regulation may adversely affect our operations in unanticipated ways. Environmental hazards may exist on the properties in which we currently hold interests, which are unknown to us at present, caused by previous or existing owners or operators of the properties.

Natural resource development projects in China are subject to periodic environmental evaluation. While these evaluations have in the past generally not resulted in substantial limitations on development activities, we expect that they will become increasingly strict in the future. Moreover, environmental awareness on the part of the public has been increasing, as has public pressure on environmental authorities. The growing environmental concerns of the public and an active environmental lobby may cause the Chinese government to impose more extensive environmental liabilities.

We are committed to carrying out our oil and gas exploration and development activities in accordance with generally accepted international environmental standards. However, our compliance with current or future environmental laws in China, the United States and elsewhere may have a material adverse effect on our business and the liabilities resulting from any environmental damage caused by our activities may be material. To the best of our knowledge, we are currently operating in compliance with all applicable environmental regulations.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater financial, technical and human resources.

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and have greater financial, technical and human resources than we do and, as a result, enjoy a competitive advantage. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

If we lose our key management and technical personnel, our business may be adversely affected.

In carrying out our operations we rely upon a relatively small group of key management and technical personnel. Messrs. David Martin, Leon Daniel and John Carver, in particular, have extensive experience in oil and gas operations throughout the world. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would be detrimental to our business.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are an oil and gas exploration and development company that currently has limited production. Until June, 1999, we had a successful producing project in Russia, but legal actions initiated in the Russian courts by our Russian joint venture partner deprived us of the right to operate the field and to realize any continuing return on our investment. As a result, we sold our interest in the project in August, 2000. See Item 3. "Legal Proceedings". Oil and gas revenue reported before 2000 was generated from our share of production from the Russian project. We have exploration and development projects in California, Texas and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically extractable reserves.

We currently have limited production exposed to commodity price risks. We are exposed to the risk that we will be unable to engage competent cost-effective contractors and suppliers for our operations, risks that damage to, or malfunction of, our equipment will hinder our ability to carry out our exploration activities and risks that foreign laws may not adequately protect our interests in disputes with foreign partners and others.

In the international petroleum industry, most production is bought and sold in United States currency or with reference to United States currency. Accordingly, we do not expect to face foreign exchange risks if and when we commence large scale commercial production. Most of our business transactions are conducted in United States currency in the countries in which we operate.

We currently have minimal debt obligations and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations and we are not currently involved in any transactions of a hedging nature.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Information

AUDITORS' REPORT

To the Shareholders of
Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2000 and 1999 and the consolidated statements of income and deficit and cash flow for each of the years in the three year period ended December 31, 2000. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

With respect to the consolidated financial statements for the year ended December 31, 2000 we conducted our audit in accordance with Canadian generally accepted auditing standards, and United States generally accepted auditing standards. With respect to the consolidated financial statements for each of the years in the two year period ended December 31, 1999, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2000 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
February 23, 2001

(signed) Deloitte & Touche LLP
Chartered Accountants

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA - U.S. REPORTING DIFFERENCES

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 10 to the financial statements, in 2000 the Company changed its method of accounting for income taxes to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations Section 3465.

Calgary, Alberta
February 23, 2001

(signed) Deloitte & Touche LLP
Chartered Accountants

IVANHOE ENERGY INC.

Consolidated Balance Sheets
(stated in thousands of U.S. Dollars)

	As at December 31, 2000	As at December 31, 1999
Assets		
Current Assets		
Cash	$29,694	$ 2,637
Accounts receivable	4,532	1,349
Notes receivable — current	325	250
Deposits	333	137
Prepaid expenses and advances	214	188
	35,098	4,561
Deposits — long-term	192	233
Notes receivable	50	350
Investments in Russian projects *(Note 4)*	—	16,200
Oil and gas equipment held for sale	—	3,265
Capital assets *(Note 5)*	64,460	23,050
	$99,800	$47,659
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 2,951	$ 4,967
Convertible debenture *(Note 6)*	1,000	1,000
	3,951	5,967
Provision for site restoration	11	—
Shareholders' Equity		
Share capital *(Note 7)*	98,211	49,494
Deficit	(2,373)	(7,802)
	95,838	41,692
	$99,800	$47,659

Approved by the Board:

(signed) David Martin
Director

(signed) Leon Daniel
Director

IVANHOE ENERGY INC.

Consolidated Statements of Income and Deficit
(stated in thousands of U.S. Dollars except per share data)

	Year ended December 31, 2000	1999	1998 (Restated) (Note 10)
Revenue			
Petroleum revenue	$ 851	$ 5,460	$ 10,977
Operating revenue	—	296	—
Interest income	990	454	1,775
Gain on sale of Russian projects *(Note 4)*	12,222	—	—
	14,063	6,210	12,752
Expenses			
Operating costs	787	4,219	8,327
Project identification costs	3,732	1,735	614
General and administrative	2,829	2,639	2,294
Russian litigation	860	1,134	—
Interest and financing charges	29	91	49
Foreign exchange loss (gain)	56	(37)	(1,292)
Depletion and depreciation	341	1,714	4,729
Asset write downs *(Note 9)*	—	2,517	70,242
	8,634	14,012	84,963
Income (loss) before income taxes	5,429	(7,802)	(72,211)
Income Tax Recovery			
Current	—	—	42
Future	—	—	1,492
	—	—	1,534
Net Income (Loss)	5,429	(7,802)	(70,677)
Deficit, beginning of year	7,802	74,455	3,778
Transfer of deficit to share capital *(Note 7)*	—	(74,455)	—
Deficit, end of year	$ 2,373	$ 7,802	$ 74,455
Net Income (Loss) per share *(Note 11)*	$ 0.05	$ (0.08)	$ (0.79)
Weighted Average Number of Shares (in thousands) *(Note 11)*	119,719	99,687	89,694

IVANHOE ENERGY INC.

Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2000	1999	1998 (Restated) (Note 10)
Operating Activities			
Net income (loss)	$ 5,429	$ (7,802)	$(70,677)
Items not requiring use of cash			
Gain on sale of Russian projects	(12,222)	—	—
Asset write downs *(Note 9)*	—	2,517	70,242
Depletion and depreciation	341	1,715	4,729
Other	67	47	(1,457)
	(6,385)	(3,523)	2,837
Changes in non-cash working capital items	(5,448)	(2,707)	1,906
	(11,833)	(6,230)	4,743
Investing Activities			
Expenditures on capital assets	(40,827)	(10,728)	(30,058)
Proceeds on sale of Russian projects	28,182	—	—
Cash recovered from Tura joint venture, net of costs	240	1,198	1,215
Proceeds on sale of (expenditures on) equipment	3,288	4,352	(9,080)
Proceeds on payment of note	250	—	—
Decrease (increase) in long-term deposits	42	(63)	—
Interim funding — Sunwing Energy Ltd.	—	(329)	(1,591)
	(8,825)	(5,570)	(39,514)
Financing Activities			
Shares issued on private placements (net)	38,598	—	—
Shares issued on exercise of warrants	8,083		
Shares issued on exercise of options	1,034	735	—
Notes payable issued, assumed or repaid (net)	—	—	(2,028)
Non-current amount payable	—	—	45
	47,715	735	(1,983)
Increase (decrease) in cash for the year	27,057	(11,065)	(36,754)
Cash, beginning of year	2,637	13,702	50,456
Cash, end of year	$ 29,694	$ 2,637	$ 13,702
Supplementary Information Regarding Non-Cash Transactions ***(Note 3)***			
Included in the above are the following:			
Taxes paid	$ 8	$ 199	$ 454
Interest paid	$ 120	$ 86	$ 77
Decrease (increase) in non-cash working capital items			
Accounts receivable	$ (3,182)	$ (673)	$ 351
Note receivable	(25)	—	—
Crude oil inventory	—	584	(283)
Deposits	(196)	1,221	(1,358)
Prepaid expenses and advances	(27)	162	150
Accounts payable and accrued liabilities	(2,018)	(4,001)	3,046
	$ (5,448)	$ (2,707)	$ 1,906

IVANHOE ENERGY INC.

Notes to the Consolidated Financial Statements
(expressed in U.S. Dollars with amounts in tables being in thousands, except per share data)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) exploration and development of hydrocarbons 2) enhanced oil recovery and 3) the application of gas-to-liquids technology. Activities are currently carried out in Southern California, Texas and China. The name of the Company was changed from Black Sea Energy Ltd. to Ivanhoe Energy Inc. on June 24, 1999.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. The consolidated financial statements also conform in all material respects to United States GAAP, except for the following matters for which details are provided in the referenced notes: — the price per share used to record the acquisition of royalty interests (Note 3); — reduction of the deficit as at December 31, 1998 (Note 7); — net income (loss) per share calculation (Note 11) and additional disclosures required under United States GAAP (Note 14).

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company has adopted the U.S. Dollar as its functional currency since it is the currency of the economic environments in which the Company and its subsidiaries operate. Monetary assets and liabilities denominated in foreign currencies are converted at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the translation of foreign currency amounts are reflected in operations.

Cash

Cash includes short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company's cash, accounts receivable, notes receivable, accounts payable and accrued liabilities approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

The estimated fair value of the convertible debenture at December 31, 2000 is approximately $1,790,000.

Deposits

Deposits are primarily comprised of drilling bonds associated with the Company's California operations ($185,000) which earn interest at 6% and temporary deposits relative to contracted work on the gas-to-liquids projects ($148,000).

Oil and Gas Equipment Held for Sale

Drilling and ancillary oil and gas equipment, originally purchased for the Company's prior owned Russian operations, was being held for sale. At December 31, 2000, all equipment has been sold and proceeds of $1,367,000 are included in accounts receivable. As at December 31, 1999, the equipment was recorded at estimated net realizable value, which was less than cost.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country cost centre basis. Such expenditures include land acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both productive and non-productive wells, gathering and production facilities and equipment, and financing and administrative costs related to capital projects. Proceeds from sales of oil and gas properties are recorded as reductions of capitalized costs, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Costs of oil and gas properties accumulated within each cost centre, including a provision for future development costs, are depleted using the unit of production method based on estimated proved reserves. Significant development projects and expenditures on exploration properties are excluded from the depletion calculation until evaluated. These excluded costs are evaluated periodically for impairment.

Depletable costs, accumulated in each cost centre, net of depletion provided, future income taxes and accumulated site restoration costs, are compared annually to the non-discounted estimated future net revenues from proved reserves (based on year-end non-escalated prices), net of estimated administration and carrying costs, and related production and income taxes ("ceiling test"). Any accumulated costs in excess of the calculated ceiling test are charged to operations.

Given the uncertainties then surrounding the Company's Russian projects, commencing in 1999, the costs previously accumulated and unamortized in the non-depletable cost pool were transferred to the depletable pool and depletion of these costs provided on the unit of production method. At June 30, 1999, the carrying value of the Russian properties was transferred to Investment in Russian Properties (see Note 4).

Royalties acquired are included in oil and gas properties and recorded at cost. Royalty costs have been allocated to project areas and costs associated with producing areas are being amortized on the unit of production method based on estimated proved reserves.

Provision for Future Site Restoration

The Company has developed an estimate for future site restoration and abandonment costs and is amortizing this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision is included with depletion and depreciation expense.

Furniture and Fixtures

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Petroleum Revenue

Sales of crude oil are recognized in the period in which the crude oil is shipped to the customer.

Income (Loss)Per Share

The income (loss) per share is computed on the basis of the weighted average number of shares outstanding during each year. The potential exercise of the options disclosed in Note 7 and conversion of the convertible debenture disclosed in Note 6 do not have a material dilutive effect on the income (loss) per share under Canadian GAAP.

Income Taxes

Effective January 1, 2000, the Company has adopted the new recommendations of the Canadian Institute of Chartered Accountants with respect to future income taxes. Under these recommendations, the Company utilizes the liability method of accounting for future income taxes. Previously the Company has used the deferral method of accounting for income taxes. This change has been applied retroactively and the financial statements of the Company for the years ended December 31, 1999 and 1998 have been restated (Note 10).

Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company's assets and liabilities.

Stock Based Compensation Plan

The Company has an Equity Incentive Plan which is described in Note 7. The options are issued at market price and no compensation expenses are recognized for this plan when stock options are issued to employees. Consideration paid by employees on exercise of stock options is credited to share capital.

3. ACQUISITIONS

Sunwing Energy Ltd.

On June 22, 1999, the shareholders approved a statutory arrangement whereby the Company acquired all the issued and outstanding shares of Sunwing Energy Ltd.("Sunwing"), a private Yukon holding corporation related through a common major shareholder and director. Prior to the statutory arrangement, Sunwing was the corporate parent of the Sunwing group of companies. As part of the statutory arrangement, Sunwing was dissolved effective the close of business on June 30, 1999.

The transaction resulted in the issuance to the former shareholders of Sunwing of 17,596,000 shares of the Company based on a share exchange ratio approved by an independent committee of directors of each of the Company and Sunwing and supported by valuations and fairness opinions by the independent financial advisor of each company.

Under an interim Funding and Security Agreement dated December 11, 1998, the Company advanced $1,920,000 ($1,591,000 advanced to December 31, 1998) of non-interest bearing interim loan funding to Sunwing pending finalization of the transaction. The interim funding provided during 1998 and 1999, and the shares issued to consummate the transaction, comprise the aggregate purchase price.

The common shares of the Company issued to complete the acquisition were valued at $0.30 per share, being the market value per share at the date the directors of the respective companies approved the share exchange ratio.

Diatom Petroleum Inc.

On May 1, 1998, Diatom, an unrelated private Nevada corporation based in Bakersfield, California, entered into an exploration agreement with Aera Energy LLC ("Aera"), a limited liability company owned

by Shell Oil Company and Mobil Corp. Under the exploration agreement, Diatom was granted certain exclusive exploration rights, with the right to participate at a minimum of 12.5% in prospects identified in an area of more than 250,000 acres in the Southern San Joaquin Valley. The exploration agreement gave Diatom access to all of Aera's exploration, seismic and technical data in the region, for the purpose of identifying drillable exploration prospects within the exclusive area until September 1, 2001.

The Company successfully negotiated a farm-in to Diatom's exploration arrangements with Aera in 1998 and, subsequently, acquired all of the issued and outstanding shares of Diatom, pursuant to an agreement dated June 18, 1999, in exchange for 500,000 common shares of the Company valued at $1.14 per share, being the market value per share at the date of the agreement.

Overriding Royalty

Pursuant to the terms of the Aera Exploration Agreement, Diatom has the right to earn a 3.5% overriding royalty (the "Diatom Royalty") on production generated from exploration activities. Prior to the Company's acquisition of Diatom, the rights to the Diatom Royalty were subdivided as follows:

- a sub-royalty equal to three-sevenths of the Diatom Royalty was allocated to the (now former) principals of Diatom and is known as the "Founders' Royalty";
- a sub-royalty equal to two-sevenths of the Diatom Royalty was allocated to a pool known as the "Common Royalty Pool" to be shared among the consulting geologists and petroleum engineers retained on behalf of Diatom to perform Diatom's exploration obligations under the Aera Exploration Agreement; and
- a sub-royalty equal to two-sevenths of the Diatom Royalty was allocated to a pool known as the "Finders' Royalty Pool" to be shared among those consulting geologists and engineers carrying out analysis of technical data leading to the identification of exploration prospects on the Aera lands.

In October, 1999 the Company acquired a 50% interest in the Founders' Royalty, together with a series of other overriding royalties which relate to lands in the San Joaquin Valley not covered by the Aera Exploration Agreement, for $860,000 and the issue of 1,562,000 common shares of the Company, at an ascribed value per share of $2.02 (Cdn.$2.98), representing the market price per share at the date of issue discounted to recognize a six month securities regulatory hold period on the shares. The aggregate value of $4,023,000 has been capitalized. See Note 5 "Capital Assets — United States".

In March, 2000, the Company exercised an option it acquired in September 1999, and issued 523,000 common shares to acquire a 37.5% interest in the Common Royalty Pool. The ascribed value per share was $1.76 (Cdn.$2.55), representing the market price per share at the date of issue, discounted to recognize the securities regulatory hold period on the shares, for an aggregate value of $917,000. Under an arrangement with Diatom, the members of the Common Royalty Pool had the option of either increasing their percentage ownership in the Common Royalty Pool, based on hours worked, or receiving remuneration from Diatom for the hours worked, resulting in Diatom earning an interest in the pool. At the date of the Company's acquisition of the 50% of the Common Royalty Pool held by members other than Diatom, Diatom held a direct 25% interest in the pool. This arrangement remains in effect and, to date, Diatom has acquired additional interests of 0.072% of the Common Royalty Pool.

For United States GAAP purposes, the aggregate value attributed to the 1999 acquisition of the Founders' Royalty interest is $5,216,000, representing 1,562,000 common shares of the Company issued at $2.79 (the per share value at the date the acquisition agreement was signed), and the $860,000 cash paid on closing. The effect of this change for United States GAAP purposes is to increase capital assets and share capital each by $1,193,000. For United States GAAP purposes, the aggregate value attributed to the March, 2000 acquisition of the Common Royalty Pool interest is $1,082,000, consisting of 523,000 shares issued at $2.07 representing the market price per share at the date the directors elected to exercise the option to acquire the interest. The effect of this change for United States GAAP purposes is to increase capital assets and share capital each by $165,000.

At December 31, 2000, the Company in aggregate held a 1.437% overriding royalty in production from lands covered by the Aera Exploration Agreement.

Subsequent to year end, the Company entered into an agreement to acquire overriding royalties, ranging from 1.75% to 6.58%, in certain lands in the San Joaquin Valley covered by the Aera Exploration Agreement. The aggregate purchase price to be paid for these additional royalties is $3,950,000, being 800,000 shares at a value of $4.94 per share, being the market value per share at the date of the signing of the purchase agreement.

Net Assets Acquired and Consideration Paid (Cash and Non-Cash)

	Years Ended December 31				
	2000	1999			
	Overriding Royalties	Sunwing	Diatom	Overriding Royalties	Total
Investing activities, net assets acquired:					
Petroleum properties	$917	$10,136	$548	$4,023	$14,707
Other long-term assets	—	544	20	—	564
Working capital (deficiency)	—	(1,721)	—	—	(1,721)
Convertible debenture assumed	—	(1,000)	—	—	(1,000)
	917	7,959	568	4,023	12,550
Financing activities, non-cash:					
Shares issued as consideration	917	5,279	568	3,163	9,010
Cash consideration	$ —	$ 2,680	$ —	$ 860	$ 3,540
Comprised of:					
Interim funding	$ —	$ 1,920	$ —	$ —	$ 1,920
Direct costs associated with acquisition	—	760	—	—	760
Cash on closing	—	—	—	860	860
	$ —	$ 2,680	$ —	$ 860	$ 3,540

4. INVESTMENT IN RUSSIAN PROJECTS

The Company was initially incorporated to pursue energy opportunities in Russia and, at one time, held three licenses to exploit oil and gas projects in Russia: a 50% interest in an exploration and development project at the Kalchinskoye field ("Tura") in western Siberia, a 50% interest in an exploration project at the Radonezh field (a block adjacent to Tura and highly success-dependent on the success of Tura) and, an enhanced oil recovery project in the Krasnodar region near the Black Sea. The Krasnodar project was determined to be uneconomic and was abandoned in 1998.

In May and June of 1998, the Company's Russian partner in its highly successful producing Tura project, commenced a series of legal actions aimed at invalidating the Tura license and gaining 100% control of the project. Although the Company defended the actions vigorously in Russia and commenced international arbitration proceedings in Stockholm, the Russian partner prevailed in the Russian courts and took over control of Tura effective June 11, 1999.

For accounting purposes at December 31, 1998, the carrying value of all the Company's Russian properties was written down by $46,724,000 through the application of the ceiling test guidelines promulgated under GAAP. Based on the Company's loss of control of the Tura project in June, 1999, effective June 30, 1999 operations of the Company's Russian projects ceased to be proportionately consolidated and the carrying value of the investment in Russian projects was again reviewed in relation to its then estimated net realizable value. No further write-down was considered necessary.

In August, 2000, a negotiated settlement was reached resulting in the disposition of the Russian properties, including the Radonezh project, for cash proceeds of $28,182,000, net of $840,000 of

settlement and severance costs. The proceeds exceeded the then carrying value of the Company's investment in the Russian projects and the resulting gain of $12,222,000 is included in income.

5. CAPITAL ASSETS

Capital assets categorized by geographic location are as follows:

	China	USA	Total
December 31, 2000			
Oil and gas properties and equipment	$18,887	$32,349	$51,236
Less:			
Accumulated depletion	—	(254)	(254)
	18,887	32,095	50,982
Gas to Liquids			
Master license	—	10,000	10,000
Equity investment in Sweetwater partnership	—	2,000	2,000
Other costs	—	1,253	1,253
	—	13,253	13,253
Furniture and fixtures	—	262	262
Less:			
Accumulated depreciation	—	(37)	(37)
	—	225	225
	$18,887	$45,573	$64,460

	China	USA	Total
December 31, 1999			
Oil and gas properties and equipment	$13,245	$9,762	$23,007
Furniture and fixtures	—	37	137
Less:			
Accumulated depreciation	—	(4)	(4)
	—	33	33
	$13,245	$9,795	$23,040

In 1999, in addition to the above, there is $10,000 of net furniture and fixtures in Canada that was fully depreciated in 2000.

	Years ended December 31		
	2000	1999	1998
Depletion and Depreciation			
Charged to operations	$ 330	$1,683	$4,664
Capitalized to property	—	39	203
Charged to inventory	—	172	1,204
	$ 330	$1,894	$6,071
Capitalized General and Administrative Expenses, related directly to acquisition, exploration and development activities	$1,549	$ 898	$ 722

Gas-to-Liquids

During 2000, the Company acquired a master license from Syntroleum Corporation permitting the Company to use Syntroleum's proprietary gas-to-liquid process ("GTL") in an unlimited number of GTL projects around the world except North America, China and India. The Syntroleum process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, cleaner-burning diesel fuel. The Company views the process as holding significant potential for monetizing uneconomic stranded gas reserves in large gas-prone regions of the world.

On October 5, 2000, the Company signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project under development in Western Australia. The plant, which will be located on the Burrup Peninsula in Western Australia, will convert natural gas contracted from the North West Shelf Venture Partners, to ultra-clean synthetic specialty products such as lubricants, industrial fluids and paraffins as well synthetic fuels. Under the terms of the letter of intent, the Company's 13% interest will cost a total of $21,000,000, of which $2,000,000 has been paid and will be used by Syntroleum, solely to fund front-end engineering and other project development expenses. Payment of the remaining $19,000,000, is subject to satisfaction of various conditions, including Syntroleum obtaining project financing. The Company's participation does not require any further financial commitments and entitles the Company to participate in 13% of the project cash flow each year. The Sweetwater plant is currently scheduled for completion in 2003.

United States

The Company has submitted 14 preliminary prospects to Aera (see Note 3 "Acquisitions — Diatom Petroleum Inc.") and has thereby retained those areas as exclusive areas for the Company to identify drillable prospects. Six drillable prospects have been identified to date and submitted to Aera. Aera has elected to participate in four of the prospects and, as a result, the Company will have working interests in those prospects ranging from 12.5% to 47%. Aera will act as operator for these prospects and drilling is expected to commence in late 2001 or 2002. In the two prospects where Aera has elected not to participate, the Company will have a 100% working interest. In one of these prospects, South Midway Sunset, the Company has drilled 21 wells during 2000 and commenced commercial production during the third quarter of 2000.

The Company is continuing to identify prospects within the 14 preliminary prospect areas and is working to develop other preliminary prospects in the acreage covered by the Aera exploration agreement, as well as in other lease acreage acquired by the Company in the Valley but not covered by the Aera exploration agreement.

In 2000, the Company acquired a 62.5% (96.15% for the first four wells) working interest in an exploration play in the Permian Basin in West Texas. Commercial production also commenced on this acreage during the third quarter. Through a series of transactions in late 2000 and early 2001 the Company acquired a working interest in over 28,400 gross (20,700 net) acres in the Bossier trend in East Texas, where drilling is expected to commence during the third quarter of 2001.

China

The Company, through Sunwing, holds two production sharing contracts to develop existing oil fields in the Daqing and Dagang regions of the People's Republic of China. These two contracts entered into by Sunwing with the China National Petroleum Corporation ("CNPC"), a state-owned company established under the laws of the People's Republic of China, were approved by the Chinese Ministry of Foreign Trade and Economic Cooperation on November 13, 1996 and November 13, 1997, respectively.

The contracts primarily take the form of production sharing agreements, whereby the Company incurs 100% of the costs to earn approximately 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery. Value added tax of 5% is payable on oil produced from both projects with a 2.5% priority production allocation to CNPC in the Daqing project. No other royalties are

payable with respect to oil production from the two projects provided that annual gross production from the relevant project does not exceed 500,000 tonnes.

Each contract calls for the planning and completion of a pilot testing phase followed by a full field development plan and implementation. The pilot program is to assess the technological and economic viability of the project.

At Daqing, the pilot program was completed successfully in 1998. While the decision was made to continue on to the field development plan, the Company chose to delay the process and, by agreement, CNPC took over operatorship of the field and the right to all revenue generated and responsibility for all costs incurred. The field development plan was completed in 2000 and approved by the relevant regulatory agencies in February 2001. Operatorship is expected to revert back to the Company by the end of the first quarter in 2001.

At the Company's Dagang project, the pilot testing phase was completed in February 2001. Nippon Oil Exploration Limited of Japan earned a 20% working interest in the Company's interest in the project, by funding a disproportionate share of the Dagang pilot testing expenditures. The decision has been made to proceed with the preparation of the development plan for submission to CNPC during the latter half of 2001. During the development plan preparation and approval process the Company will continue operatorship of the Dagang project.

During the pilot testing phase, for accounting purposes, the results of operations were credited to the project costs. With the evaluation stage now completed and the decision made to enter the development and implementation stage, all operating results will, in the future, be included in the Company's consolidated statement of income. At Daqing, this will occur once the Company assumes operatorship of the field.

6. CONVERTIBLE DEBENTURE

The $1,000,000 convertible debenture bears interest at U.S. prime plus 2.5%, is due on the earlier of August 4, 2002 or within 90 days following written demand, and is convertible into common shares (principal and interest, accrued and unpaid, all or in part) of the Company at Cdn.$2.75 per share up to August 4, 2002.

7. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

The total number of issued and outstanding common shares is as follows:

	Number of Common Shares (thousands)	Amount
Balance December 31, 1997 and 1998	89,694	$114,157
Issued on exercise of options	1,162	735
Issued for services	25	47
Issued on acquisition of		
Sunwing Energy Ltd. (Note 3)	17,596	5,279
Diatom Petroleum Inc. (Note 3)	500	568
Overriding royalties (Note 3)	1,562	3,163
Reduction of stated capital	—	(74,455)
Balance December 31, 1999	110,539	49,494
Issued for Private Placements, net	11,250	38,598
Issued on exercise of warrants	2,998	8,083
Issued on exercise of options	1,545	1,034
Issued on acquisition of Consultants Royalty Management (Note 3)	523	917
Issued for services	19	85
Balance December 31, 2000	126,874	$ 98,211

The December 31, 2000 share dollar amount is net of a loan of $236,000 (December 31, 1999 — $307,000) advanced to an employee to assist in the exercise of incentive stock options as permitted under the Employees' and Directors' Equity Incentive Plan.

Private Placements and Share Purchase Warrants

During 2000, the Company issued common shares under two private placements. In January and February 2000, the Company issued 6,250,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of $14,014,000. Each two warrants are exercisable into one common share at Cdn.$4.00 until the first anniversary date of the private placement. At December 31, 2000, 255,000 of these warrants for the purchase of 127,500 common shares remain unexercised. Subsequent to year end, the balance of these warrants were exercised.

On October 17, 2000, the Company issued 5,000,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of $24,584,000. Each two warrants are exercisable into one common share at $5.375 until the first anniversary date of the private placement. At December 31, 2000, all of the warrants remain outstanding for purchase of 2,500,000 common shares.

Reduction of Stated Capital

The shareholders approved, on June 22, 1999, the reduction of stated capital in respect of the common shares by an amount of $74,455,000 being equal to the accumulated deficit as at December 31, 1998. Under United States GAAP, a reduction of the deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under United States GAAP, share capital and deficit each are increased by $74,455,000 at December 31, 1999 and 2000.

Equity Incentive Plan

The Company has an Employees' and Directors' Equity Incentive Plan and under this plan it grants, from time to time, stock options to directors, officers and employees to purchase common shares at the quoted market value on the date of the grant. These options are conditional on continuing employment and vest at the discretion of the Board of Directors. Prior to 1999, all options granted vested over a three year period and expired ten years from date of issue. Options granted after March 1, 1999 were granted

on identical terms and vest over a five year period and expire five years from date of issue. By shareholders resolution in 1998, the exercise price of the options issued in 1997 were repriced from Cdn.$4.65 to Cdn.$1.75.

Following is a summary of the status of the Company's Equity Incentive Plan, including changes during the years ended:

	December 31, 2000		December 31, 1999		December 31, 1998	
	Number of Shares	Weighted-Average Exercise Price	Number of Shares	Weighted-Average Exercise Price	Number of Shares	Weighted-Average Exercise Price
	(000's)	(Cdn.$)	(000's)	(Cdn.$)	(000's)	(Cdn.$)
Outstanding at beginning of period	7,800	$1.18	8,090	$0.93	3,385	$1.75
Granted	1,991	6.39	2,065	2.56	7,300	0.70
Exercised	(1,545)	1.17	(1,162)	1.33	—	—
Cancelled/forfeited	(85)	3.00	(1,193)	1.75	(2,595)	1.35
Outstanding at end of period	8,161	$2.45	7,800	$1.18	8,090	$0.93
Options exercisable at period end	5,356	$1.24	4,328	$0.92	3,560	$1.13

The following table summarizes information respecting stock options outstanding at December 31, 2000:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
(Cdn.$)	(000's)		(Cdn.$)	(000's)	(Cdn.$)
$0.50 to $1.75	4,500	7.9 years	$0.61	4,466	$0.61
$2.50 to $3.40	1,670	4.0 years	$2.69	491	$2.75
$6.13 to $7.62	1,991	5.0 years	$6.39	398	$6.39
$0.50 to $7.62	8,161	6.4 years	$2.45	5,356	$1.24

Subsequent to December 31, 2000, the following options were exercised: 2,500 at Cdn.$1.75, 10,000 at Cdn.$1.01 and 33,333 at Cdn.$0.50. In addition, 100,000 options were granted at Cdn.$7.53.

8. SEGMENT INFORMATION

Geographic segment results from operations for the years ended December 31, 2000, 1999 and 1998 are detailed below.

	Year ended December 31, 2000			
	Canada	China	USA	Total
Petroleum revenue	$ —	$ —	$ 851	$ 851
Other revenue	197	8	785	990
	197	8	1,636	1,841
Operating costs	—	—	787	787
Project identification costs	3,732	—	—	3,732
Capital taxes	—	1	—	1
General and administration	1,610	677	541	2,828
Interest and financing	—	27	2	29
Depletion and depreciation	10	31	300	341
Foreign exchange (gain) loss	56	—	—	56
	5,408	736	1,630	7,774
Income (loss) for year	$ (5,211)	$ (728)	$ 6	(5,933)
Gain on sale of Russian investments				12,222
Russian litigation costs				(860)
Net income				$ 5,429
Capital expenditures				
Acquired for cash	$ —	$ 5,676	$35,151	$40,827
Acquired for shares	—	—	917	917
	$ —	$ 5,676	$36,068	$41,744
Identifiable assets	$ 7,342	$20,836	$71,622	$99,800

	Year ended December 31, 1999				
	Russia	Canada	China	USA	Total
Petroleum revenue	$ 5,460	$ —	$ —	$ —	$ 5,460
Operating revenue	296	—	—	—	296
Other revenue	55	393	1	5	454
	5,811	393	1	5	6,210
Operating costs	4,219	—	—	—	4,219
Project identification costs	—	1,735	—	—	1,735
Capital taxes	—	176	—	—	176
General and administration	210	1,152	923	178	2,463
Interest and financing	—	72	19	—	91
Russian litigation	—	1,134	—	—	1,134
Depletion and depreciation	1,665	32	14	3	1,714
Foreign exchange (gain) loss	(61)	29	(5)	—	(37)
Asset write downs	—	2,437	—	—	2,437
	6,033	6,767	951	181	13,932
Loss for year	$ (222)	$ (6,374)	$ (950)	$ (176)	(7,722)
Peru asset impairment					(80)
Net loss					$ (7,802)
Capital expenditures					
Acquired for cash	$ 1,283	$ 3	$ 3,532	$ 5,830	$10,648
Acquired for shares	—	—	9,749	3,731	13,480
	$ 1,283	$ 3	$13,281	$ 9,561	24,128
Peru — cash					80
					$24,208
Identifiable assets	$16,200	$ 6,784	$14,448	$10,227	$47,659

	Year ended December 31, 1998		
	Russia	Canada	Total
Petroleum revenue	$ 10,977	$ —	$ 10,977
Operating revenue	107	1,668	1,775
Other revenue	—	—	—
	11,084	1,668	12,752
Operating costs	8,327	—	8,327
General and administration	450	1,811	2,261
Project identification costs	—	614	614
Capital taxes	—	33	33
Interest and financing	—	49	49
Depletion and depreciation	4,645	84	4,729
Foreign exchange (gain) loss	(1,347)	55	(1,292)
Asset write downs	47,948	8,794	56,742
	60,023	11,440	71,463
Income (loss)	(48,939)	(9,772)	(58,711)
Income tax recovery	1,534	—	1,534
Income (loss) for year	$ (47,405)	$ (9,772)	$ (57,177)
Peru asset impairment			(13,500)
Net loss			$ (70,677)
Capital expenditures			
Acquired for cash	$ 16,326	$ 4	$ 16,330
Equipment for sale	—	9,098	9,098
	$ 16,326	$ 9,102	25,428
USA			227
Peru			13,500
			$ 39,155
Identifiable assets	$ 21,203	$ 27,753	$ 48,956
USA			486
			$ 49,442

During 2000, three customers represented greater than 10% of total sales, being 44%, 40% and 12% respectively, for an aggregate of 96%.

During 1999, two customers represented greater than 10% of total sales, being 85% and 11% respectively, for an aggregate of 96%. In 1998, the Company derived its revenue from various customers, four of which represent greater than 10% of total sales. These four customers respectively represent 28%, 21%, 15% and 14% of total sales, for an aggregate of 78%.

9. ASSET WRITE-DOWNS

Asset write-downs include the following amounts:

	Year Ended December 31,	
	1999	1998
Ceiling test write-down of Russian properties (Note 4)	$ —	$46,724
Provision for impairment of Peru costs	80	13,500
Write down of oil and gas equipment to estimated net realizable value	2,437	8,794
Write down of crude oil inventory to estimated net realizable value		1,224
	$2,517	$70,242

During 1998, the Company, through its wholly-owned U.S. subsidiary, entered into an agreement with Pangaea International Ltd. ("Pangaea"), a Canadian private company controlled by a major shareholder and director of the Company. Under the agreement, the Company earned a 50% interest in Pangaea's Block 71, a 2.5 million acre hydrocarbon exploration and development concession located in the Ucayali Basin in east central Peru, by incurring the cost associated with completing the initial well. The Company's costs associated with the initial well were estimated at approximately $13,500,000, an amount approximately equal to what Pangaea had spent to date.

In December, 1998, the first well was drilled and while there were some minor oil shows they were not deemed to be of economic significance and the well was abandoned. The Company and Pangaea relinquished Block 71 during 2000.

10. INCOME TAXES

As described in Note 2, the Company has adopted the liability method of accounting for income taxes retroactively and has restated its financial statements. The effect of the restatement is to increase the deficit at the beginning of the year ended December 31, 1998 by $929,000 to $3,778,000, increase the recovery of future taxes for the year ended December 31, 1998 to $1,492,000 and decrease the net loss for the year ended December 31, 1998 to $70,677,000.

The accounting policy has not resulted in a change to the financial statements of the Company for the year ended December 31, 1999. In addition, this change in accounting policy does not result in a substantive change to the financial position or the results of operations as at and for the year ended December 31, 2000. As a result of this change under Canadian GAAP, the Company's financial statements are now also in compliance with United States GAAP with respect to income taxes.

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. Details of the determination of the actual income tax expense for each of the three years is detailed below. For ease of presentation, the loss, as a result of the write down of Russian assets, and the subsequent gain on settlement has been classified as Russian operations, even though neither of these two items will have any tax effect in Russia. The actual loss of approximately $35 million, being the aggregate investment, ignoring accounting write downs, less proceeds received on settlement will be a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely.

In 1999 and 1998, expenditures incurred in Peru were made through the Company's U.S. subsidiary, and as a consequence, are deductible in the U.S. For determination of income tax expense (recovery), activities in Peru have been combined with those in the U.S.

	Year Ended December 31,		
	2000	1999	1998
Source income (loss) before income taxes	$ 5,429	$ (7,802)	$(72,211)
Composite statutory income tax rate	43.20%	42.78%	37.20%
Expected income tax (recovery)	$ 2,345	$ (3,338)	$(26,866)
Non-deductible expenses for tax purposes		78	
Application of tax benefits not recognized previously	(2)		
Tax benefit of write-down (gain) of Russian assets not recognized	(4,908)		15,595
Tax benefit not recognized	2,565	3,260	9,737
Income tax expense	$ —	$ —	$ (1,534)

In 1999, concurrent with the loss of field operations in Russia, the Company ceased proportionately consolidating the Russian results. The amounts displayed above for 1999 are for the first six months of 1999 only.

The tax loss carry-forwards in Canada are Cdn. $27,049,000 and in the United States $24,436,000. The tax losses carry-forward in Canada expire between 2003 and 2007, in the United States between 2018 and 2020. In China the Company has available for carry-forward against future Chinese income $31,822,000 of cost basis. Due to the uncertainty of utilizing these tax losses carry-forwards and the benefit of deductible temporary differences, the Company has made a valuation allowance of an equal amount against these potential recoverable amounts as detailed below. The substantial increase in 1999 resulted from the acquisition of Sunwing.

	As at December 31,		
	2000	1999	1998
Future tax assets	$ 23,909	$ 23,439	$ 9,832
Valuation allowance	(23,909)	(23,439)	(9,832)
Net future tax liability	$ —	$ —	$ —

11. NET INCOME (LOSS) PER SHARE

The Company, in connection with its initial public offering in June 1997, placed in escrow 31,457,000 common shares held by certain shareholders, to be released one-third per year on the succeeding three anniversary dates of the public offering. For Canadian GAAP, as the release of shares from escrow is based on time rather than on any performance criteria, these shares are considered issued and outstanding and form part of the calculation of earnings and fully dilutive earnings per share. Under United States GAAP, these escrow shares are considered issued and outstanding only after they are released from escrow.

Under Canadian GAAP, fully diluted net income (loss) per share amounts are calculated by applying the imputed earnings method to the stock options outstanding in order to assess the dilutive impact. Under United States GAAP, the net income (loss) per share amounts are calculated using the treasury method in order to assess the dilutive impact of stock options.

As a result, under United States GAAP the calculation of net income (loss) per share is different from the calculation under Canadian GAAP. The relevant amounts calculated under United States GAAP are as follows:

	Year Ended December 31,		
	2000	1999	1998
United States GAAP			
Net income (loss) per share	$ 0.05	$ (0.09)	$ (1.10)
Weighted average number of shares (in thousands)	115,065	84,547	64,069

12. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, office space and facilities. Costs are accumulated and the Company is billed its proportionate share based on usage.

The costs incurred in the normal course of business with respect to the above arrangements amounted to $1,581,000 for 2000; $1,692,000 for 1999, and $1,004,000 for 1998. Included in accounts payable are amounts due under these arrangements totaling $486,000 (1999 — $953,000, 1998 — $183,000) respectively.

13. COMPARATIVE FIGURES

Certain of the comparative amounts have been reclassified to conform to the presentation adopted for the current year.

14. ADDITIONAL DISCLOSURES REQUIRED UNDER UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")

The Company's consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with United States GAAP, except for certain matters which were mentioned in Note 2. Where these matters impact the financial statements, the details of the differences are as follows:

Consolidated Statements of Income

The application of United States GAAP would not have any effects on net income as reported, except on Net Income (Loss) per share (Note 11).

The Company has no items which would be disclosed as other comprehensive income under United States GAAP.

Stock based compensation

In 1995, the United States Financial Accounting Standards Board issued Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation." The Company has a stock-based compensation plan as more fully described in Note 7. With regards to its stock option plan, the Company applies APB Opinion No. 25, as interpreted by FASB ("FIN") 44, in accounting for this plan and accordingly no compensation cost has been recognized. Had compensation expense been determined based on fair value at the grant date for the stock option grants consistent with the method

of SFAS No. 123, the Company's net loss and net loss per share would have been reduced to the pro forma amounts indicated below:

	Year ended December 31,		
	2000	1999	1998
Net income (loss) under United States GAAP (thousands)	$5,429	$ (7,802)	$ (70,677)
Pro forma (thousands)	$3,289	$ (11,840)	$ (72,012)
Net income (loss) per common share under United States GAAP	$ 0.05	$ (0.08)	$ (0.79)
Pro forma	$ 0.03	$ (0.12)	$ (0.80)
Stock options issued during period (thousands)	1,991	2,065	7,300
Weighted average exercise price	$ 4.29	$ 1.73	$ 0.36
Weighted average fair value of options granted during the period	$ 2.32	$ 1.96	$ 0.24
Compensation cost (thousands)	$ —	$ —	$ —

The foregoing information is calculated in accordance with the Black-Scholes option pricing model, using the following data and assumptions: volatility, as of the date of grant, computed using the prior one to three-year weekly average prices of the Company's common shares, which ranged from 59% to 108%; expected dividend yield — 0%; option terms to expiry — 5 to 10 years as defined by the option contracts; risk-free rate of return as of the date of grant — 5.09% to 5.70%, based on five year Government of Canada Bond yields.

Consolidated Balance Sheets

The application of United States GAAP would have the following effects on balance sheet items as reported:

Shareholders' Equity

Shareholders' equity at December 31, 1999 under Canadian GAAP	$41,692
Adjustment to ascribed value of shares issued for royalty interests (Note 3)	1,193
Shareholders' equity at December 31, 1999 under United States GAAP	$42,885
Shareholders' equity at December 31, 2000 under Canadian GAAP	$95,838
Adjustment to ascribed value of shares issued for royalty interests in 1999 (Note 3)	1,193
Adjustment to ascribed value of shares issued for royalty interests in 2000 (Note 3)	165
Shareholders' equity at December 31, 2000 under United States GAAP	$97,196

Under United States GAAP, the transfer of deficit to share capital which occurred during the year ended December 31, 1999 would not be recognized (Note 7). As a result, shareholders' equity under United States GAAP would comprise the following:

	As at December 31,	
	2000	1999
Share capital (including adjustments above)	$174,024	$125,142
Deficit	(76,828)	(82,257)
	$ 97,196	$ 42,885

Capital Assets

There are certain differences between the full cost method of accounting for oil and gas assets as applied in Canada and as applied in the United States. The principal difference results in the method of performing ceiling test evaluations under the full cost accounting rules. Under Canadian GAAP, non-discounted future net revenues from oil and gas production, less an estimate for future general and

administrative expenses, financing costs and income taxes are compared to the carrying value of the depletable petroleum properties, whereas for United States GAAP future net revenues are discounted to present value at 10% per annum and compared to the carrying value of the depletable petroleum properties. The Company has performed the ceiling test in accordance with US GAAP and determined that no material variances in financial statements balances would have resulted.

The Company capitalizes certain internal costs on the basis that they relate directly to the acquisition, exploration and development activities and do not include costs related to production, general corporate overhead, or similar activities. Included in capital assets are the following capitalized internal costs:

2000	$1,549
1999	$ 898
1998	$ 722

The categories of costs included in the cost of oil and gas properties and equipment, including the adjustments, in accordance with U.S. GAAP, to the ascribed value of shares issued for royalty interests of $1,193,000 in 1999 and $165,000 in 2000 (Note 3) are as follows:

	As at December 31 2000	As at December 31 1999	As at December 31 1998
Unproved properties	$26,180	$13,960	$ 25,735
GTL license, investment and other costs	13,253	—	—
Mineral interests in properties	7,468	7,468	24,987
Wells and related production equipment and facilities	18,946	2,771	35,307
Support equipment	368	174	2,230
	66,215	24,373	88,259
Accumulated depletion and depreciation	(397)	(130)	(68,517)
	$65,818	$24,243	$ 19,742

The 1999 balances have been reduced by the reclassification of the net Russian properties, as discussed in Note 2.

As at December 31, 2000 cost of unproved properties included in capital assets are as follows:

		Incurred in		
	Total	2000	1999	1998
Acquisition	$10,268	$ 6,391	$ 3,878	$ —
Exploration	9,373	4,507	4,639	227
Royalty Rights	6,539	1,322	5,217	—
	$26,180	$12,220	$13,733	$227

Accounts payable and accrued liabilities

The following is the breakdown of accounts payable and accrued liabilities:

	As at December 31 2000	As at December 31 1999
Accounts payable	$2,912	$4,957
Accrued liabilities	39	10
Total	$2,951	$4,967

Significant accrual balances include:

	As at December 31,	
	2000	**1999**
Salaries and related expenses	$ —	$ —
Income and other taxes	$ —	$ —
Other general and administrative	$ 29	$ —
Interest	$ 10	$ 10

Consolidated Statements of Cash Flow

The application of United States GAAP would have no effect on the statements of cash flow as reported.

Impact of New and Pending U.S. GAAP Accounting Standards

Statement of Financial Account Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), was issued in June 1998, by the Financial Accounting Standards Board. SFAS 133, as amended by SFAS 137 and 138, establishes new accounting and reporting standards for derivative instruments and for hedging activities. This statement requires an entity to establish, at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity's approach to managing risk. SFAS 133 will be effective for the 2001 fiscal year. The Company has completed a preliminary assessment of the effect, if any, that SFAS 133 will have on its consolidated balance sheet at December 31, 2000. prepared under U.S. GAAP. The only adjustment that would be required on adoption of SFAS 133 relates to the fair value of the convertible debenture, which at December 31, 2000 exceeds the book value by $790,000. This would increase liabilities and deficit by $790,000 at January 1, 2001

In December 1999, the staff of the Securities and Exchange Commission released Staff Accounting Bulletin (SAB 101), "Revenue Recognition", to provide guidance on the recognition, presentation and disclosure of revenue in financial statements. Management believes that its revenue recognition practices are in conformity with SAB 101.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company's oil and gas producing activities is presented in accordance with United States Statement of Financial Accounting Standards No. 69: Disclosures About Oil and Gas Producing Activities.

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company's working interest share of reserves net of royalties. The reserves for 2000 in the U.S. are based on estimates by the independent petroleum engineering firms of Duke Engineering & Services and Joe C. Neal & Associates. In China, the reserves are based on estimates by Gilbert Laustsen Jung Associates Ltd. The reserves in Russia at December 31, 1998 are based on estimates by the independent petroleum engineering firm, D&S Reservoir Engineering Ltd. The reserves presented for December 31, 1999 represent reserves in China acquired through the acquisition of Sunwing during 1999 and are based on estimates by the independent engineering firm of Gilbert Laustsen Jung Associates Ltd.

The Company's net proved and net proved developed oil and gas reserves were as follows:

	Oil (MBbl)	Gas (MMcf)
Net proved reserves, December 31, 1997	42,300	
Kuban discontinued operations	(9,700)	
Production	(1,823)	
Revisions of previous estimates	(21,977)	
Net proved reserves, December 31, 1998	8,800	
Production	(807)	
Loss of remaining reserves in Russia	(7,993)	
Acquisition — Sunwing	20,848	
Net proved reserves, December 31, 1999	20,848	
Extensions and discoveries	4,803	6,301
Production	(133)	(5)
Revisions to previous estimates	276	
Net proved reserves, December 31, 2000	25,794	6,296
Net Proved Developed Reserves		
December 31, 1998	6,700	—
December 31, 1999	—	—
December 31, 2000	1,573	984

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following standardized measure of discounted future net cash flows from proved oil and gas reserves has been computed using period end prices of $23.95 per barrel of oil ($22.95 per barrel in 1999 and $5.95 per barrel in 1998) and $5.65 per Mcf of gas and costs and period end statutory tax rates. A discount rate of 10% has been applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future rather than year end prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2000	1999	1998
		(in thousands)	
Future cash inflows	$653,419	$469,260	$ 52,339
Future development and restoration costs	162,399	130,283	5,044
Future production costs	145,130	86,253	37,506
Future income taxes	102,831	79,878	2,859
Future net cash flows	243,059	172,846	6,930
10% annual discount	141,823	101,736	1,747
Standardized measure	$101,236	$ 71,110	$ 5,183

Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2000	1999	1998
Sale of oil & gas net of production costs	$ (64)	$ (1,310)	$ (2,924)
Revenue credited to China property costs	(2,940)	(92)	—
Net changes in pricing and productions costs	(3,433)	834	(42,622)
Purchase of reserves	—	71,202	—
Discoveries and extensions	19,266	—	—
Abandonment of reserves	—	(4,707)	(7,912)
Revisions of previous estimates	1,707	—	(16,061)
Net change in future development costs	9,611	—	22,899
Accretion of discount	5,979	—	6,431
Increase (decrease)	30,126	65,927	(40,189)
Standardized measure, beginning of year	71,110	5,183	45,372
Standardized measure, end of year	$101,236	$ 71,110	$ 5,183

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities for the following periods ended:

	Year ended December 31,	
	2000	1999
	(in thousands)	
Property Acquisition		
Proved	$ —	$ 7,468
Unproved	6,392	3,878
Royalty rights	1,157	5,216
Development	16,436	4,086
Exploration	4,508	4,753
GTL license, investment and other costs	13,252	—
	$41,745	$25,401

Depletion, Depreciation and Amortization per unit of net production, before write-down under ceiling test:

	$/boe
Russia	
Year ended December 31, 1999	$3.04
Year ended December 31, 1998	$1.74
United States	
Year ended December 31, 2000	$8.70

Results of Producing Activities:

	Year ended December 31,		
	2000	1999	1998
Sales	851	5,460	10,977
Production expense	787	4,150	8,053
Write-down of crude oil inventory	—	—	1,224
Depletion (including write-down under ceiling test)	275	1,665	51,369
Other	—	(48)	(730)
Income (loss) before income taxes	(211)	(307)	(48,939)
Income tax (recovery)	—	—	(605)
Results of operations from producing activities	(211)	(307)	(48,334)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID MARTIN, age 69 Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 - present); President, Cathedral Mountain Corporation (1997 - present); President and Chief Executive Officer, Occidental Oil & Gas Corporation (1986-1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 50 Hong Kong	Deputy Chairman (since June, 1999) and Director (since February 1995)	Chairman and President, Ivanhoe Capital Corporation
E. LEON DANIEL, age 64 Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 - present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); President, Occidental Engineering Co. (1993-1996); President, Worldwide Exploration, Occidental Petroleum (1997-1998)
JOHN A. CARVER, age 68 Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum (1997-1998); Consultant (1996-1997); Executive Vice President, Worldwide Exploration, Occidental Oil and Gas Corporation (1994-1996)
R. EDWARD FLOOD, age 55 Reno, Nevada	Director (since June, 1999)	Mining Analyst, Haywood Securities (May, 1999 - present); Deputy Chairman, Ivanhoe Mines Inc. (May, 1999 - present); President, Ivanhoe Mines Inc. (1995-1999); Member and Gold Analyst of Contrarian Fund Management Team of Robertson Stephens & Company (1993-1995)

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
SHUN-ICHI SHIMIZU, age 60 .... Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 to present)
JOHN O'KEEFE, age 52 .... Houston, Texas	Executive Vice-President, Investor Relations and Chief Financial Officer (since September, 2000)	Executive Vice-President, Investor Relations and Chief Financial Officer of Ivanhoe Energy Inc. (September 2000 - present); Vice-President, Investor Relations of Santa Fe Snyder Corporation (1999 - September 2000); Director, Investor Relations of Oryx Energy Company (1991-1999)
PATRICK CHUA, age 45 .... Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 - present); Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 - June, 1999); Co-Chairman and director, Sunwing Energy Ltd. (BVI) (May, 1995 - Present); prior thereto, Project Manager and Senior Engineer, Sproule Associates Limited
GERALD MOENCH, age 55 .... Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 - present); President and Director, Sunwing Energy Ltd. (July, 1997 - June, 1999); Acting President, Sunwing Energy Ltd. (June, 1996 - July, 1997); Consultant in Indonesia and New Zealand (January, 1995 - June, 1996); prior thereto, General Manager, Santos Petroleum (Seram) Ltd.
BRADLEY C. SHOUP, age 42.......... Dallas, Texas	Executive Vice-President (since August, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (August 1999 - present); Chief Financial Officer of Ivanhoe Energy Inc. (January, 2000 - September, 2000); Partner, Relational Investors LLC (1996 - 1999); Partner, Batchelder & Partners, Inc. (1988 - 1996)

Listed below are those of our directors who hold directorships in other publicly listed corporations and the names of those corporations:

ROBERT M. FRIEDLAND:	Ivanhoe Mines Ltd.
R. EDWARD FLOOD:	Diamond Fields International Ltd., Emperor Mines Limited, Ivanhoe Mines Ltd.

Each of our directors was elected at our last annual general meeting of shareholders. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director's office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation and Benefits Committee. The members of the Audit Committee are Messrs. Shun-Ichi Shimizu, Edward Flood and John Carver. The members of the Compensation and Benefits Committee are Messrs. David Martin, Edward Flood and Robert Friedland.

Based solely on a review of the reports furnished to us, we believe that during 2000 all of our directors, executive officers and 10% shareholders complied with the applicable requirements for reporting initial ownership and changes in ownership of our common shares.

ITEM 11. EXECUTIVE COMPENSATION

During the fiscal year ended December 31, 2000, we paid our executive officers $873,000 in aggregate cash compensation. We do not provide any retirement pension plan or retirement compensation agreement for our directors and officers.

The following executive compensation disclosure relates to our President and Chief Executive Officer as at December 31, 2000, and each of our four most highly compensated executive officers (collectively, the "named executive officers") whose annual compensation exceeded $100,000 in the year ended December 31, 2000. During the year ended December 31, 2000, the total compensation paid to those of our officers who received more than $100,000 in total compensation was $886,182.

Summary Compensation

We paid the following compensation during the years ending December 31, 1998, 1999 and 2000 to each of our named executive officers.

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation	Securities Under Options/SARs Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts ($)	All Other Compensation ($)
E. LEON DANIEL President & Chief Executive Officer(1)	2000	200,000	22,000		500,000			
	1999	148,580		1,144(6)				
	1998				500,000			
PATRICK CHUA Executive Vice President(2)	2000	180,000		4,711(6)				1,530
	1999	133,722		6,892(6)	500,000			
	1998							
BRADLEY C. SHOUP Executive Vice President Corporate Development(3)	2000	161,000		1,940(6)				
	1999				300,000			
	1998							
DAVID MARTIN Chairman(4)	2000	50,000	110,000					
	1999							
	1998				4,000,000			
GERALD MOENCH Executive Vice President(5)	2000	150,000		3,112(6)				745
	1999	111,435		4,583(6)	200,000			
	1998							

(1) Mr. E. Leon Daniel was appointed as our President and Chief Executive Officer on June 22, 1999, and has been one of our directors since August 25, 1998.

(2) Mr. Chua was appointed as an Executive Vice-President in June, 1999.

(3) Mr. Shoup has been an Executive Vice President since August, 1999. He was also Chief Financial Officer from January to September, 2000.

(4) Mr. Martin has been our Chairman and one of our directors since August, 1998.

(5) Mr. Moench was appointed an Executive Vice-President in June, 1999.

(6) Includes premiums paid by us on behalf of the named executive officer for medical, dental and other health insurance coverage.

Options and Stock Appreciation Rights (SARs)

We granted the following Options/SARs to our named executive officers in the financial year ended December 31, 2000:

OPTION/SAR GRANTS IN LAST FISCAL YEAR

Name	Number of Securities Underlying Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Fiscal Year	Exercise of Base Price ($/Sh)	Expiration Date	Grant Date Present Value $(1)
E. Leon Daniel	500,000	25.558	$6.13	June 29, 2005	$6.13

(1) Equal to or greater than the weighted average price of our common shares on The Toronto Stock Exchange for the five trading days preceding the date of a grant.

Aggregated Option Exercises

The aggregate number of options exercised by any of the named executive officers during the financial year ended December 31, 2000 was 766,666.

AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FINANCIAL YEAR END OPTION/SAR VALUES

Name	Shares Acquired on Exercise (#)	Aggregate Value Realized ($)	Number of Underlying Securities Unexercised Options/SARS at FY-End (#) Exercisable/ Unexercisable	Value of Unexercised in the Money Options/SARS at FY-End (Cdn.$) Exercisable/ Unexercisable
E. Leon Daniel	166,666	941,663	166,667/0	1,158,336/0
David Martin	600,000	3,765,000	3,400,000/0	23,630,000/0

Pension Plans

We do not presently provide a pension plan for our employees.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

We have no written employment contracts or termination of employment or change of control arrangement with any of our directors or named executive officers.

Director and Named Executive Officer Compensation

We do not generally pay cash or other fixed compensation to our directors. However, on a recommendation from the Compensation and Benefits Committee, the Board awarded directors' fees to Mr. David Martin in the amount of $110,000, Mr. E. Leon Daniel in the amount of $22,000 and Mr. John Carver in the amount of $100,000. Also, as we call on the expertise of Mr. Carver beyond the ordinary scope of his requirements as one of our directors, we will pay Mr. Carver a supplemental director's fee of $30,000 per quarter. We reimburse our directors for expenses they reasonably incur in the performance of their duties as directors and they are also eligible to receive stock bonus awards from time to time and to participate in our Employees' and Directors' Equity Incentive Plan.

The cash compensation we pay to the named executive officers is intended to be comparable to the cash compensation paid to executive officers of similar companies who have comparable duties and responsibilities.

Employees' and Directors' Equity Incentive Plan

Our Employees' and Directors' Equity Incentive Plan, as amended (the "Plan") consists of three component plans: a common share option plan (the "Share Option Plan"), a common share bonus plan (the "Share Bonus Plan"), and a common share purchase plan (the "Share Purchase Plan"). The purpose of the Plan is to advance our corporate interests, by encouraging equity participation by our directors, officers and employees through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the board of directors to grant options to acquire our common shares in favour of our directors, officers and employees. Options are subject to adjustment in the event of a subdivision or consolidation of our common shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers and employees, who are, in the opinion of our board of directors, in a position to contribute to our future growth and success.

In determining the number or value of optioned common shares made subject to options, we consider the optionee's present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The board of directors determines the date of grant, the number of shares, the exercise price per share, the vesting period, and all other terms and conditions of the options we grant. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant.

Unless earlier terminated upon an optionee's death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

We may also grant share appreciation rights when we grant an option. Such rights permit an optionee to elect to terminate the option and instead receive common shares on the basis of a cashless exercise. The number of common shares that an optionee who exercises share appreciation rights will receive is equal to the difference between the then fair market value per common share and the option price per common share of all common shares under option, divided by the then fair market value per common share.

Share Bonus Plan

The Share Bonus Plan permits our board of directors to issue a maximum of 1,000,000 of our common shares as bonus awards to our directors and employees on a discretionary basis having regard to such merit criteria as the board of directors may determine.

Share Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the board of directors) of continuous service on a full-time basis and who are designated by the board of directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly instalments. We then make contributions on a quarterly basis equal to the employee's contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant's behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares which we may issue or reserve for issuance under the Plan is currently 12,000,000 common shares. Any increase is subject to stock exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares.

Our board of directors has the right to amend, modify or terminate our Equity Incentive Plan. However, any amendment to the Equity Incentive Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to stock exchange approval and the approval of our shareholders.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2000, our Compensation and Benefits Committee consisted of Messrs. Robert Friedland, Edward Flood and David Martin. Mr. Martin is one of our executive officers. Mr. Friedland is our largest shareholder and holds interests in other entities with which we have transacted, and continue to transact, business. See Item 13. "Certain Relationships and Related Transactions."

Board Compensation Committee Report on Executive Compensation

The Compensation and Benefits Committee administers our executive compensation program, which is designed to provide incentives for our executive officers to enhance shareholder value. Our principal objectives are to attract and retain qualified executives critical to our success, to provide fair and competitive compensation, to align their interests with those of our shareholders, and to reward extraordinary corporate and individual performance on an annual basis. We structure each compensation package in a manner that we believe links shareholder return, measured by appreciation in share price,

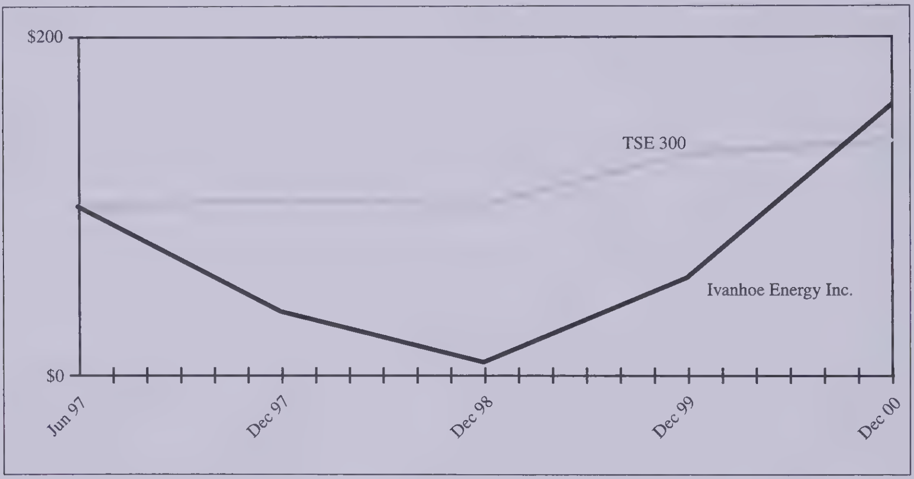
with executive compensation. Stock options are the primary mechanism we use to align management and shareholder interests. We do not offer pension plans to our senior executives.

Submitted on behalf of the Compensation Committee:

Mr. Robert Friedland
Mr. Edward Flood
Mr. David Martin

Performance Graph

The following graph and table show changes since we completed our initial public offering of common shares in June, 1997 and the value of $100 invested in our common shares:



	June 11, 1997	Dec. 31, 1997	Dec. 31, 1998	Dec. 31, 1999	Dec. 31, 2000
Ivanhoe Energy Inc.	Cdn. $ 100	Cdn. $ 38	Cdn. $ 8	Cdn. $ 58	Cdn. $ 160
TSE 300 Total Return Index	Cdn. $ 100	Cdn. $ 104	Cdn. $ 101	Cdn. $ 131	Cdn. $ 139

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Except as set forth below, no person or group is known to beneficially own (as deemed by SEC Regulations) 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares at March 1, 2001.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class
Common Shares	Robert M. Friedland(2) Flat B, 31st Floor Primrose Court 56A Conduit Road Mid-Levels, Hong Kong	45,402,120	35.74%
Common Shares	Capital Research and Management Company 333 South Hope Street Los Angeles, California 90071	13,500,000(3)	10.45%
Common Shares	Paul Stephens 388 Market Street Suite 200 San Francisco, California 94111	7,531,100	5.93%
Common shares	RS Investment Management 388 Market Street Suite 200 San Francisco, California 94111	7,963,624	6.27%
Common Shares	Directors and Officers as a Group (11 persons)	53,376,710(4)	40.14%

(1) Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) 44,827,120 outstanding common shares are held indirectly through Newstar Securities Ltd., Premier Mines Limited and Evershine LLC, companies controlled by Mr. Friedland.

(3) Includes 2,500,000 common shares issuable upon exercise of share purchase warrants.

(4) Includes 5,916,667 common shares issuable upon the exercise of incentive stock options held by directors and officers as a group.

Security Ownership of Management

The following table sets forth the beneficial ownership at March 1, 2001 of our common shares by each of our directors, our named executive officers and by all of our directors and executive officers as a group:

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percentage of Class
Common Shares	David Martin	903,663	0.71
Common Shares	Robert M. Friedland	45,402,120	35.74
Common Shares	E. Leon Daniel	502,018	0.40
Common Shares	John A. Carver	195,000	0.15
Common Shares	R. Edward Flood	56,466	0.04
Common Shares	Shun-ichi Shimizu	32,500	0.03
Common Shares	John O'Keefe	25,000	0.02
Common Shares	Patrick Chua	275,776	0.22
Common Shares	Gerald Moench	5,000	—
Common Shares	Bradley Shoup	37,500	0.03
Common Shares	All directors and executive officers as a group (10 persons)	47,435,043	37.34%

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Management and Others

We issued 3,220,000 of our common shares and an equal number of share purchase warrants in February, 2000 to certain of our directors and executive officers as part of a private placement of 6,250,000 common shares and share purchase warrants. Units consisting of one common share and one share purchase warrant were issued at a price of Cdn.$3.25 per unit. 4,000,000 units were purchased by an arm's length institutional investor. The names of our directors and executive officers and the number of securities each of them purchased are as follows:

Name	Number of common shares and share purchase warrants (Units)
Robert M. Friedland	1,985,000
David Martin	100,000
E. Leon Daniel	10,000
John Carver	10,000
R. Edward Flood	30,000
Shun-ichi Shimizu	5,000
Patrick Chua	55,000
Bradley Shoup	25,000

Certain Business Relationships

We are parties to cost sharing agreements with other companies in which Mr. Robert M. Friedland has a material direct or indirect beneficial interest. Through these agreements, we share office space, furnishings, equipment and communications facilities in Vancouver, Singapore and London and an aircraft on a cost recovery basis. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2000, our share of these

costs was $2,207,000. The companies with which we are parties to the cost sharing agreements, and Mr. Friedland's ownership interest in each of them, are as follows:

Company Name	Robert Friedland Ownership Interest
Ivanhoe Mines Ltd.	51.71%
Ivanhoe Capital Corporation	100%
African Minerals Ltd.	46%
Diamond Fields International Ltd.	7.85%
Pangaea Energy International Ltd.	72%

TABLE OF INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Name and Principal Position	Involvement of Issuer or Subsidiary	Largest Amount Outstanding During 2000	Amount Outstanding as at March 1, 2001
DAVID MARTIN Chairman	Loan Agreement	$0.00	$201,629
R. EDWARD FLOOD Director	Loan Agreement	$0.00	$ 60,489

We loaned Messrs. Martin and Flood the above-mentioned amounts in January, 2001 to facilitate their exercise of warrants to purchase 50,000 and 15,000 of our common shares respectively. The loans bear interest at the Bank of Montreal prime rate as quoted from time to time and the loans mature on January 26, 2002. The loans are secured by a pledge of the 50,000 common shares owned by Mr. Martin and the 15,000 common shares owned by Mr. Flood.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

The following financial statements and exhibits are filed as part of this Annual Report:

(a) 1. **Financial Statements:**

Deloitte & Touche, LLP Auditors' Report on Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2000 and 1999 and Consolidated Statements of Loss and Deficit and Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2000, 1999 and 1998.

Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2000 and 1999.

Consolidated Statements of Loss and Deficit of Ivanhoe Energy Inc. for the years ended December 31, 2000, 1999 and 1998.

Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2000, 1999 and 1998.

Notes to the Consolidated Financial Statements of Ivanhoe Energy Inc. for the years ended December 31, 2000, 1999 and 1998.

2. **Financial Statement Schedules:**

Supplementary Disclosures about Oil and Gas Production Activities (Unaudited)

3. **Exhibits**

3.1 Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

3.2 Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

4.1 Amended and Restated Convertible Loan Agreement dated August 4, 1999 between Ivanhoe Energy Inc. and Linyi Holdings Ltd. (incorporated by reference to Exhibit 3.2 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.1 Funding and Participation Agreement dated August 1, 1998 between Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.) and Diatom Petroleum, Incorporated (incorporated by reference to Exhibit 3.3 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.2 Exploration Agreement dated May 1, 1998 between Diatom Petroleum, Incorporated and Aera Energy LLC, as amended January 18, 1999, March 29, 1999, September 15, 1999, September 21, 1999 and April 5, 2000 (incorporated by reference to Exhibit 3.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.3 Participation Agreement dated August 1, 1996 between Aera Energy LLC (formerly CalResources, LLC), Digital Petrophysics, Inc., Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.) (as assignee of Texaco Exploration and Production Inc.) and Wood Oil Company, as amended December 11, 1998 and further amended October 13, 1999 (incorporated by reference to Exhibit 3.5 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.4 Participation Agreement dated February 15, 1999 between Aera Energy LLC, Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.), Diatom Petroleum, Inc. and Armstrong Resources, LLC, as amended September 9, 1999 and further amended November 15, 1999 (incorporated by reference to Exhibit 3.9 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.5 Diatom Petroleum, Incorporated Stock Purchase Agreement dated June 18, 1999 between Ivanhoe Energy Inc. (formerly Black Sea Energy Inc.), William R. Berry II, Deborah M. Olson and Michael P. Stark, as amended July 2, 1999 (incorporated by reference to Exhibit 3.10 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.6 Digital Petrophysics Resources, Inc. Stock Purchase Agreement dated September 3, 1999 between Ivanhoe Energy (USA) Inc. and William R. Berry II and Deborah M. Olson (incorporated by reference to Exhibit 3.11 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.7 Purchase Agreement for Sanford ORRI dated September 3, 1999 between Ivanhoe Energy (USA) Inc. and William R. Berry II and Deborah M. Olson (incorporated by reference to Exhibit 3.12 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.8 Purchase Agreement for Founders' Royalty dated September 3, 1999 between Ivanhoe Energy (USA) Inc. and Michael P. Stark (incorporated by reference to Exhibit 3.13 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.9 Option to Purchase Stock Agreement dated September 20, 1999 between Ivanhoe Energy (USA) Inc. and the shareholders of Consultants Royalty Management, Inc. (incorporated by reference to Exhibit 3.14 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.10 Farmout Agreement dated April 8, 1999 between Nippon Oil Exploration Limited and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.16 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.11 Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.12 Petroleum Contract for Zhou 13 Block in Zhao Zhou Oilfield, Daqing, The People's Republic of China, dated August 8, 1996, between China National Petroleum Corporation and Sunwing Energy Ltd. (incorporated by reference to Exhibit 3.17 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.13 Exploration Agreement dated October 1, 1999 between Prime Natural Resources, LLC, Ivanhoe Energy (USA) Inc. and Aera Energy LLC (incorporated by reference to Exhibit 3.23 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.14 Service Agreement dated September 1, 1999 of CUE Management Consultants Limited (incorporated by reference to Exhibit 3.31 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.15 Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).

10.16 Agreement dated May 11, 2000 between Discovery Operating, Inc., Don L. Sparks and Ivanhoe Energy (USA) Inc. (incorporated by reference to Exhibit 3.38 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).

10.17 Consultancy Agreement dated June 2, 2000 between Ivanhoe Energy Inc. and M&A Oil Consultancy Limited (incorporated by reference to Exhibit 3.39 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).

10.18 Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc.

10.19 Consulting Agreement dated November 15, 2000 between Ivanhoe Energy Inc. and Continental Energy Limited.

10.20 Employees' and Directors' Equity Incentive Plan.

10.21 Agreement for the Sale and Purchase of Shares in Great Plains Petroleum (Cyprus) Limited and Global Petroleum (Cyprus) Limited dated August 10, 2000 between Kuban Petroleum Ltd., Ivanhoe Energy Inc. and Stesana Enterprises Limited.

10.22 Deed of Release dated August 10, 2000 between Ivanhoe Energy Inc., Kuban Petroleum Ltd., Tyumen Oil Company and Tyumeneftegaz.

10.23 Agreement to Purchase shares of Digital Petrophysics, Inc. dated January 26, 2001 between Ivanhoe Energy (USA) Inc., William R. Berry II and Deborah M. Olsen.

10.24 Memorandum of Understanding dated February 13, 2001 between PetroChina Company Limited and Sunwing Energy Ltd. to conduct a Joint Feasibility Study of Zitongxi and Zitongdong Blocks.

10.25 Memorandum of Understanding dated February 13, 2001 between PetroChina Company Limited and Sunwing Energy Ltd. to conduct a Joint Feasibility Study of Yudong Block.

21.1 Subsidiaries of Ivanhoe Energy Inc.

23.1 Consent of D&S Reservoir Engineering Ltd., Petroleum Engineers (incorporated by reference to Exhibit 3.34 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

23.2 Consent of Gilbert Laustsen Jung Associates Ltd., Petroleum Engineers.

23.3 Consent of Duke Engineering & Services.

23.4 Consent of Joe C. Neal & Associates.

(b) **Reports on Form 8-K:**

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IVANHOE ENERGY INC.

By: /s/ E. LEON DANIEL

Name: E. Leon Daniel
Title: President and Chief Executive Officer

Dated: March 16, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ E. LEON DANIEL E. Leon Daniel	President, Chief Executive Officer and Director (Principal Executive Officer)	March 16, 2001
/s/ JOHN O'KEEFE John O'Keefe	Executive Vice-President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 16, 2001
/s/ DAVID MARTIN David Martin	Chairman of the Board and Director	March 16, 2001
/s/ ROBERT M. FRIEDLAND Robert M. Friedland	Deputy Chairman and Director	March 16, 2001
/s/ JOHN A. CARVER John A. Carver	Director	March 16, 2001
/s/ R. EDWARD FLOOD R. Edward Flood	Director	March 16, 2001
/s/ SHUN-ICHI SHIMIZU Shun-ichi Shimizu	Director	March 16, 2001

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Fax: 86 10 6505 5259

Qatar

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Grand Hammad
Doha, Qatar
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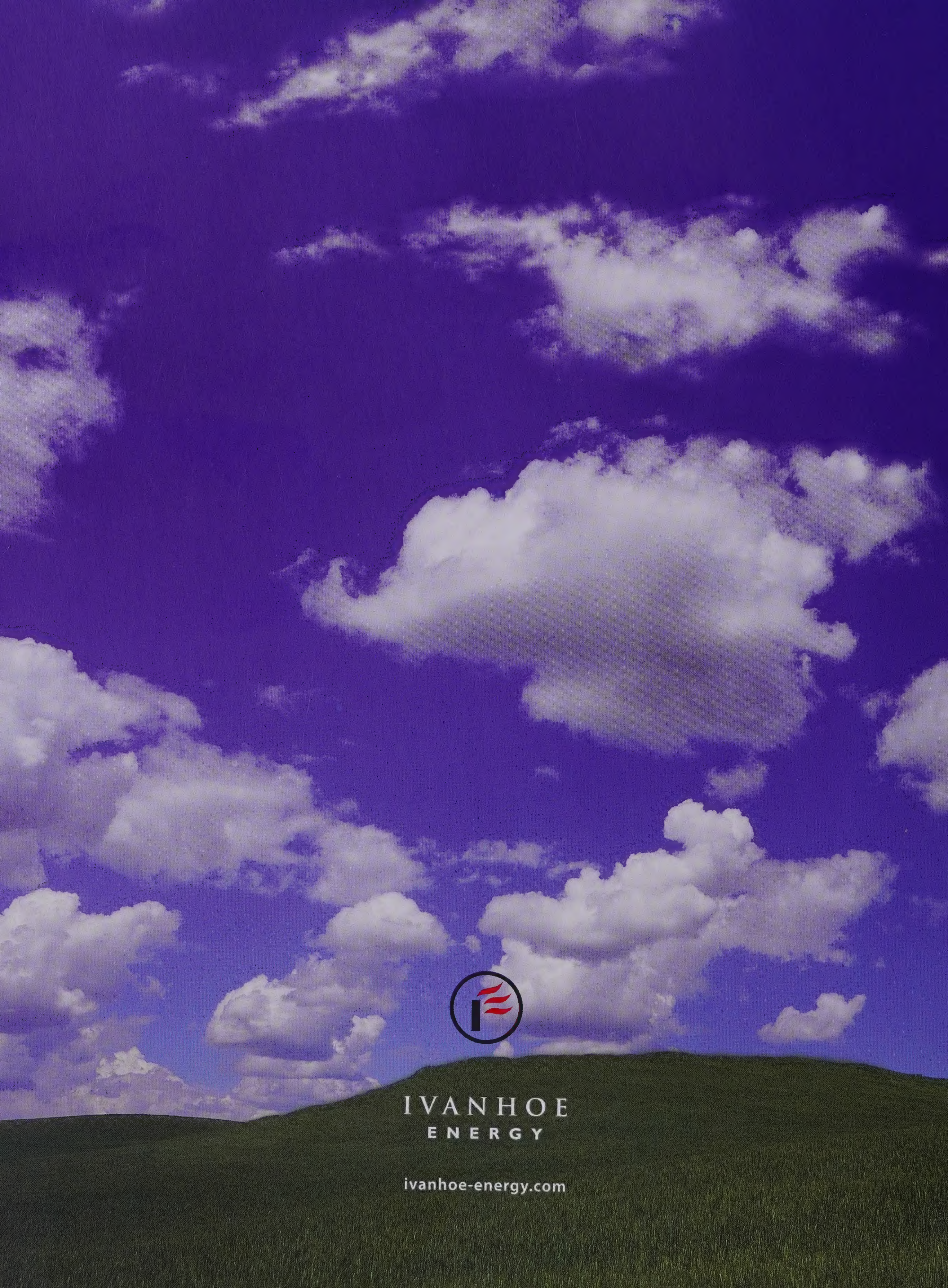
Fax: 974 435 5219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